BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number

ELECTRICITY MARKET DESIGN AND STRUCTURE : RM01-12-000

- x

PJM INTERCONNECTION, L.L.C. : Docket Number

ALLEGHENY ELECTRIC COOPERATIVE, INC. : RT01-2-001

ATLANTIC CITY ELECTRIC COMPANY :

BALTIMORE GAS & ELECTRIC COMPANY :

DELMARVA POWER & LIGHT COMPANY :

JERSEY CENTRAL POWER & LIGHT COMPANY :

METROPOLITAN EDISON COMPANY :

PECO ENERGY COMPANY :

PENNSYLVANIA ELECTRIC COMPANY :

PPL ELECTRIC UTILITIES CORPORATION :

POTOMAC ELECTRIC POWER COMPANY :

PUBLIC SERVICE ELECTRIC & GAS COMPANY :

UGI UTILITIES, INC. :

- x Docket Number

ALLEGHENY POWER : RT01-10-000

- x

AVISTA CORPORATION : Docket Number

MONTANA POWER COMPANY : RT01-15-000

NEVADA POWER COMPANY :

PORTLAND GENERAL ELECTRIC COMPANY :

PUGET SOUND ENERGY, INC. :

SIERRA PACIFIC POWER COMPANY :

- x Docket Number

SOUTHWEST POWER POOL, INC. : RT01-34-000

- x

AVISTA CORPORATION : Docket Number

BONNEVILLE POWER ADMINISTRATION : RT01-35-000

IDAHO POWER COMPANY :

MONTANA POWER COMPANY :

NEVADA POWER COMPANY :

PACIFICORP :

PORTLAND GENERAL ELECTRIC COMPANY :

PUGET SOUND ENERGY, INC. :

SIERRA PACIFIC POWER COMPANY :

- x

GRIDFLORIDA, LLC : Docket Number

FLORIDA POWER & LIGHT COMPANY : RT01-67-000

FLORIDA POWER CORPORATION :

TAMPA ELECTRIC COMPANY :

- x

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CAROLINA POWER & LIGHT COMPANY : Docket Number
DUKE ENERGY CORPORATION : RT01-74-000
SOUTH CAROLINA ELECTRIC & GAS COMPANY :
GRIDSOUTH TRANSCO, LLC :
- x Docket Number
ENTERGY SERVICES, INC. : RT01-75-000
- x Docket Number
SOUTHERN COMPANY SERVICES, INC. : RT01-77-000
- x
CALIFORNIA INDEPENDENT SYSTEM OPERATOR : Docket Number
CORPORATION : RT01-85-000
- x
BANGOR HYDRO-ELECTRIC COMPANY : Docket Number
CENTRAL MAINE POWER COMPANY : RT01-86-000
NATIONAL GRID USA :
NORTHEAST UTILITIES SERVICE COMPANY :
THE UNITED ILLUMINATING COMPANY :
VERMONT ELECTRIC POWER COMPANY :
ISO NEW ENGLAND, INC. :
- x Docket Number
MIDWEST INDEPENDENT SYSTEM OPERATOR : RT01-87-000
- x Docket Number
ALLIANCE COMPANIES : RT01-88-000
- x

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NSTAR SERVICES COMPANY : Docket Number

: RT01-94-000

- x

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.: Docket Number

CENTRAL HUDSON GAS & ELECTRIC CORPORATION : RT01-95-000

CONSOLIDATED EDISON COMPANY OF NEW YORK, :

INC. :

NIAGARA MOHAWK POWER CORPORATION :

NEW YORK STATE ELECTRIC & GAS CORPORATION :

ORANGE & ROCKLAND UTILITIES, INC. :

ROCHESTER GAS & ELECTRIC CORPORATION :

- x Docket Number

PJM INTERCONNECTION, L.L.C. : RT01-98-000

- x Docket Number

REGIONAL TRANSMISSION ORGANIZATIONS : RT01-99-000

- x Docket Number

REGIONAL TRANSMISSION ORGANIZATIONS : RT01-100-000

- x Docket ARIZONA

PUBLIC SERVICE COMPANY : RT02-1-000

EL PASO ELECTRIC COMPANY : EL02-9-000

PUBLIC SERVICE COMPANY OF NEW MEXICO :

TUCSON ELECTRIC POWER COMPANY :

WESTCONNECT RTO, LLC :

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Commission Meeting Room 2-C

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Tuesday, January 22, 2002

The above-entitled matter came on for technical conference, pursuant to notice, at 9:30 a.m., Alice M. Fernandez, presiding.

BEFORE COMMISSIONERS:

CHAIRMAN PAT WOOD, III

COMMISSIONER LINDA KEY BREATHITT

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER WILLIAM L. MASSEY

APPEARANCES:

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DAVID E. MEAD

Office of Markets, Tariffs and Rates

Federal Energy Regulatory Commission

-- continued --

APPEARANCES (CONTINUED):

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Federal Energy Regulatory Commission

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Federal Energy Regulatory Commission

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PJM Interconnection (PJM)

CHARLES KING, Vice President

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Markets Development

ISO-New England, Inc. (ISO-NE)

ROBERTO PALIZA, Principal Consultant

Midwest ISO (MISO)

P R O C E E D I N G S

(9:30 a.m.)

MS. FERNANDEZ (Presiding): Could people start taking their seats so we can get started. We have a long day ahead of us and I'd like to try to keep to schedule.

(Pause.)

Good morning, and welcome to our conference on standard market design. Sort of in keeping with our power point theme for the day --

(Slide.)

I see mine's already up there. Let me introduce, first off, some of the people that we have from the Commission Staff. We have Mark Hegerle from the Office of Markets, Tariffs and Rates, Dave Withnell from the Office of General Counsel, David Mead from the Office of Markets, Tariffs, and Rates. I'm Alice Fernandez from OMTR. We also have Dick O'Neill from OMTR, Dan Larcamp, Shelton Cannon, and Kevin Kelly from OMTR. We also have a number of other Staff sort of sprinkled throughout the area.

(Slide.)

I guess I would sort of like to start with giving a basic overview of the conference and the basic objective of this. The primary objective of this session is to sort of increase the understanding of the existing market designs, some that are in existence, some that are proposed to go into existence very soon. Basically we view this as primarily an educational session, so that people understand both the similarities and the differences of these market designs. As such, especially today, we're not going to get into what we hope is an awful lot of debate on them but more just sort of understanding of them.

(Slide.)

Today's conference is going to focus on the market designs that are currently in existence or proposed for the northeast and the midwest. Tomorrow morning, we're going to be talking about the market designs and issues that are proposed for the Northwest and already in effect in Texas.

In the afternoon, we're going to have a sort of roundtable discussion where we can discuss the differences among the market designs and perhaps start the process of identifying best practices among them.

(Slide.)

Just in terms of the status, this just lists the market designs that are in effect. There are some that are proposing some major changes in the near future, those being California ISO and ISO New England.

(Slide.)

There are also, in terms of the Midwest ISO and RTO West, they are also considering long-term market design changes.

(Slide.)

As sort of a general matter, there are going to be copies of all of the presentations that we have for this session. There are copies that are in the back of the room. We are intentionally putting them out for the day's session so that today we have the morning session is out there. We'll put out those in the afternoon after lunch.

The copies of these are also going to be available on FERC's Web site, if you don't get one, or if you're listening to the broadcast. They will be available there too.

As sort of a general sort of starting point for today, the speakers today are going to get into a lot more detail about the market designs in the Northeast and the Midwest. What I've included in this is several charts that just give sort of an overview of some of the similarities and the differences in major areas. In terms of the energy markets, I see we've been joined by Commissioner Breathitt. In terms of the energy markets, the market designs in the Northeast and the Midwest all propose to use LMP for congestion pricing. All are proposing to have both day ahead and real time markets.

The major difference, as you'll see in the energy markets, deals with how losses are treated, and also how sort of the concept of generation adequacy as to whether or not there is a specific mechanism for it or not.

(Slide.)

In terms of the transmission, all of them basically use financial rights as the methodology. There are differences among them as to how the hedging rights are allocated to the participants, whether or not they're assigned or whether or not they're auctioned. There also are differences in terms of the types of hedging rights that are being proposed. Those in the Northeast basically use point-to-point obligations. In the Midwest ISO there's also a consideration of using obligations as well as obligations and using flowgate rights as well as point-to-point rights.

(Slide.)

In terms of the reserve markets, there also are some more differences here than other ones. One of the major differences that you'll see in the reserve markets is that the New York ISO basically has auctions markets for all of these as to how the reserves are procured. In contrast, the other ISOs are proposing to use specific separate markets for some and not for others.

(Slide.)

Finally, in terms of market power mitigation, there are also similarities and differences. Most of them have some form of mitigation that relates to units that have to be run for liability purposes. There are differences in the amount of mitigation that is done through bid screens where there are specific mitigation actions that are triggered if bids exceed a certain percentage of historical bids. In the East, there currently is what we started calling a demand response proxy, a thousand dollar bid cap, and the final item in terms of generator bid rules is that one of the types of market power mitigation that is in effect in all of these is that there are various rules that may limit the flexibility to change bidding parameters, the effective of which is to mitigate market power. The actual rules that are in effect, there are some differences among them but they do have the same basic purpose.

(Slide.)

With that and trying to stay on schedule, our first speaker, we have a long day ahead of us so the more that we can stay on schedule, the better, is Andy Ott who is going to give a presentation on PJM's market design. This presentation is basically going to take the morning, so at a certain point in Andy's presentation we're going to take a break so that we will actually have a break before lunch, and he's going to let you know when he gets to that point.

With that, I'll turn it over to him.

MR. OTT: Thank you for setting a good example. I'll try to stay on time myself. This is the area I'm going to be talking about in this first section.

(Slide.)

Again, before I get into this, when we were thinking about a market design, when I think about market design, I think there's really four areas that I look for. One is flexibility. The market has to have a variety of options for participants to use; bilaterals, self-scheduling, spot market activity. What that does is allow the small player whose risk avers to hedge forward lock himself, make himself indifferent to spot price, while somebody else really wants the depth and liquidity of a large market to take advantage of that. So really flexibility is a key and really what it translates into is a variety of participation options, so we look for that when we're trying to design a new feature in a market or a new market.

Then you have information and consistency. I think we flood the Internet with as much real time information as we can, and we try to make that information consistent across the system in a sense that gives the market confidence, it gives the market the idea that it knows what's happening because it has all this information that it can process and the fact that it sees the consistency come out gives it much more confidence that the market is working. When you have that kind of confidence, the next area is incentive.

The point is now you've built through information and consistency, confidence. Then the market can be driven by incentives. The way we like to describe what's happening in a locational pricing system really, the system operations are the reliability function and the markets coexist. They actually complement each other. So if the market prices actually show, in a pricing signal, what the system operator wanted to happen, when you have that kind of fundamental consistency between the pricing of the market, if you will, and the reliability function, you tend to have less of the clashing. One form of clashing in the market is transmission line loading relief, or the acronym TLR, but the point is, when you have a difference where they are not consistent, where they're contradictory, if you will, then you have problems.

To the extent that you can design the thing so that they complement each other, you find that you have a much more smooth and efficient operation. The last thing is adaptability. You've got to be willing to change as the system conditions change, or the way the market participants interact change. You may need new products, you may need different products, whatever. That's really what we do when we try to design the markets.

Now I am done with my introduction. If you look at the next slide, I'm just briefly going to go into a very brief overview of PJM, probably two points.

(Slide.)

Two points we want to talk about. One here is the governance structure. We have a two-tiered governance. The Board is elected by the members, then you have the Members Committee. In this case, the governance of the market is shared but the Board has ultimate control, but it is driven by the fact that it is elected by the members so it does have accountability.

(Slide.)

This is PJM's control area. Let me throw this in, just to show you essentially the relative size. When I talk later about the types of market we have, it gives you an idea of the size and the number of generators that are participating.

(Slide.)

On the next slide again we go to what is LMP, what is locational marginal pricing. Again, it's a pricing system that reflects what is really the actual operating conditions that are occurring on the system, so the fact is it's a complementary pricing system to the real time operations. It's based on system operations. It uses the same fundamental tools that operations uses.

(Slide.)

On the next slide, we look at the components of locational pricing. Essentially, it has three components. You have the price of energy at every location. That includes three things. It includes the marginal cost of energy, which essentially is where the supply and the demand meet, then you have the cost of transmission which is how much it costs to move energy on a congested system, and you have the cost of losses. In PJM, we have not implemented the cost of marginal losses in our nodal pricing. That's a point we had discussed. Some of the areas used losses and I guess tomorrow, we can talk about the details of that instead of debating today.

(Slide.)

The next slide is probably just saying in another way so I will move forward to the next one.

(Slide.)

Now we get into transmission congestion. Essentially what you have is all systems face congestion. Sooner or later, you're going to have an area of the system where you don't have enough generation and are importing power into that area and you have some kind of limitation, so you have to take some kind of action. In our case, and in all cases I believe around the country, you have various types of limits, you have the thermal, you have stability limits, or voltage limits. The bottom line is whatever type of limit it is, it's a constraint that causes the power system to need to react to a condition that is becoming unreliable. So what you really need when you find this is you need some kind of equitable solution. You need a way to manage that problem.

(Slide.)

But you need to manage it openly and you need to show the market that the problem exists. If you can show the market the problem exists, the market can react, and that's that open consistency between the market and the operations.

(Slide.)

If you go to the next slide, if we encounter a transmission limit, we essentially, our dispatchers have three options. One option is to reconfigure the system. What that means is switch a line out of service to alleviate an overload because it changes the way power flows. Another would be to change something called a phase angle regulator which is the closest thing we have to a valve on an electric system and that just changes again the way the power flows.

The second way is to curtail contracts. When I talk about curtailing contracts, that's external contracts, contracts outside coming into the market, so that's the contracts crossing the seam, if you will, of the market. In PJM's case, we have a class of contracts that are voluntarily submitting a bid to curtail themselves when congestion becomes a problem, they don't want to pay the additional cost, so in that case, that's where we would use that option.

The third option is redispatch. That's when you're actually moving one generator to substitute for another because it's in more of an advantageous location with respect to the transmission problem. Generally speaking, when you talk about redispatch, redispatch means you're taking a more costly generator and turning it on and reducing a less costly, so there's a cost involved to that.

(Slide.)

Delivery limitations. Again, we just talked about the fact that you have a high cost generator that needs to be turned on in lieu of a low cost. The cost to operate that is essentially reflected in the price. We'll discuss in a few minutes how that actually happens, trying to avoid going into the mathematics. I think what it will show you is that it's very simple. The way it's reflected is based on the way the power actually flows on the system, so when you're looking at how the cost of moving the more expensive generation is shown to the market, by not only the cost differential but also the flow effect, in other words, how it actually changes the way power flows on the system. The thing that this really does is it creates an open market meaning it shows people what the true cost of moving this generation is relative to a specific area of the system. It also provides a way to use cost causation, meaning to assign costs to the certain areas where the constraint occurs, and again that gets down to the incentive. So that again the market is consistent because it's showing the higher price in the area where you have the problem. The market can then react and fix the reliability problem at the same time that it's trying to make the market equal.

(Slide.)

I think we're moving on. Transmission system congestion. Again, we use LMP to manage congestion. What we have is system operations is now happy. What we've said to them is, we have an LMP system, the market is consistent with what the system operators want them to do, want the participants to do. So we have the ability for people to react to price. So the system operators feel very good that they have control of the system. Now the market needs something to allow it to become a deep liquid commercial market. You have this nodal pricing system that sits down underneath everything where the price is different in every location on the system. The problem is for the commercial market to develop and to become liquid and deep. You need a certain set, or a set of a few prices that people trade at in order to sort of standardize, if you will, the market.

That's where we developed the trading hub concept or the zonal concept. The trading hubs essentially are a way to aggregate a set of nodal prices or bus prices into one single price that people can sort of use a standard definition, if you will. That way, any given participant can track a relatively few prices, meaning the ones where they are actually taking delivery or actually injecting energy into the system, plus the one where they trade on a forward basis. What that allows, the system operation then is happy because they have the full set of prices underneath and have the consistency that goes with that, the complementary nature of the market and the system operations. But also by doing these aggregations into hubs and zones, you essentially have now the commercial markets are happy because they get what they need which is a standard trading location. What that does for the system is that it allows it to develop depth, if you will. And the last part of this, once you have transmission congestion charges on the system, customers need a way to become indifferent to the spot price, and the way they do that is to buy financial transmission rights.

Again, we're going to try to standardize these names. I'm guilty of keeping my acronyms for today but in New York, I believe they are called transmission congestion contracts. At PJM, they are financial transmission rights, whatever. The point is that these are a set of transmission hedges. I think you call them hedging instruments, something like that.

MS. FERNANDEZ: Can I ask you a question on the trading hubs. In terms of the number of hubs that you have, how did you develop the specific hubs and the number of hubs?

MR. OTT: For PJM, we knew when we started LMP back in '98 that we needed to develop a hub. We went to our market committee and we more or less said to them, what do you think the user community, if you will, would need? They said well, we certainly need two hubs, one in the west and one in the east because we think that's the way power flows. PJM felt it was necessary for us to throw out candidate hubs to sort of kickstart the market. So we went and then asked the members what they wanted. They said they wanted a western hub and PJM to sort of reflect the unconstrained stock price in the western part of PJM, and they wanted an eastern hub to reflect that differential between, because PJM's constraint generally on the high voltage system going from west to east.

So I think the way you decide is you ask the members and again a lot of this, these markets are for them. We'll talk about that a little bit later too. So you sort of keep it simple and ask them. And once you ask them what they think, and the committee stakeholders decide, then our function as the RTO is to sort of facilitate and throw out candidate hubs, start posting the prices so it's easy for people to see them. That's the best answer I can give you.

MS. FERNANDEZ: To the extent that the market changes, you can add additional ones?

MR. OTT: Yes. The point is since these hubs, you have the underlying physics of the system, if you will, and the underlying full set of prices that match the actual operations since the hubs and zones are really just mathematical aggregates. They aren't like a boundary type where you're trying to define a physical boundary. You can have one location or one substation that belongs to three different hubs or three different zones or four or five, it doesn't matter. So You don't have to go back and redefine the past. If one hub, like in PJM, we actually just created a new hub. It's called the New Jersey Hub. And if you think about the New Jersey BGS auction, again it's an acronym that stands for basic generation service. They're auctioning off -- the best way to describe it is the provider of last resort responsibility in New Jersey.

One of our members called me up one day and said hey, I need another hub, and I said why, and he said because I want people to trade with me for the BGS. So we defined a hub. I think we started posting that in early December and again, the point there since it's a mathematical aggregation, we can go back in the past and say what that hub price would have been so you can get actually a history of what the price points would have been.

So you publish a definition of the hub. That's very critical. So the market knows what the commercial definition is. That's very important to the market that that stay fixed in time, that it be standard, so the hub is like a -- we have different types of aggregation and again this is just terminology. Hubs are really the ones. They're fixed in time, they're never changed, you can depend upon them to always be there.

There are zones which are load weighted points. Therefore the people who are actually delivering energy, serving real energy in that system, they're not trading, they're actually physical delivery. By doing the load weighting, it allows them, they may be delivering to 60 different substations, but giving them one price that's weighted by the delivery patterns allows them to subtract that one price, even though in the billing they'll actually see 60, but mathematically it's the same.

Then we have something called an aggregate, which is a subzone, sort of a portion of the zone. That's for retail choice. You may not be serving load or energy in the whole zone, you may only be serving a couple of different substations, and what that allows people to do is again be flexible. Again, the point of this whole thing is if a participant decides that it wants to only serve or only hedge to a portion of the zone, you have to have some way of very quickly we can define a zone if I get a call tomorrow, it could be there, as long as we get the call before noon. The point is it's not hard. You're not changing the fundamental physics of your system, it's just an accounting thing. Does that help? Okay.

I hate to do this but I think I need to go back to this slide just to point out. I think LMP -- you know, again, I've said it's nothing new, but I think it's more than, little bit more I wanted to add.

When you talk about what is this locational pricing concept, I think we've talked about the consistency of system operations. The tool set, when we actually put LMP in, the tool sets that our dispatchers used didn't change. But what did change and was very fundamental was we added a lot of process and procedures for the dispatcher to make standardized decisions. So the process was auditable, it was repeatable. You could actually trace it. You could baring in the Price Waterhouse type auditor to actually look at what was happening.

So we had a much more sophisticated system of logging. We call it the dispatch management tool. So we really just added front-end capability onto the system so the dispatcher could manage information in a consistent manner. Because now instead of being just eight utilities, now it was a much bigger market with open access. So you needed that fundamental consistency underneath and you needed the ability to track how the prices were developed. That's very important.

I think the other key I would put down here is when you open up the system and put all the information out to the participants, it really levelizes, so the small player and the larger player really can see the same information. It's just a matter of how they use it. I think that was important to what we did.

Now we can go on to how our LMPs are calculated.

(Slide.)

MR. OTT: I threw in an example together to try to explain. I hope this works in this environment. Usually I'm used to doing this up in front of a screen, but we'll try it this way. If we go to the next slide.

(Slide.)

MR. OTT: What we have is a small little power system here, and we have generation trying to meet the demand. The total demand is 900. And if you turn on all the generation in economic merit order, meaning -- the idea here is you want to turn the least costly generator on until you use it all up. Then you go to the next one and go to the next one, so you just stack them up in order.

If you do it in this case and you try to serve the load, you find you violate a transmission limitation. So you have a transmission reliability problem. If you see the line from E to D, if you allow the 253 megawatts to flow in that line, it's only capable of carrying 240. What that means is, the physics of the line, it will start to melt, if you will, or some other problem. The lines simply cannot carry that.

So what that means is, we have to go back to our previous slides. There's three options we have here. We can open the lines so that the power flows somewhere else. Obviously, it's not going to overload if it's open. We can try to use a controllable device. We don't have any on this system, so it's not an option. We could cut contracts, but we have no contracts, because there's only five buses, so now we have to redispatch.

So what we say is, since we can't serve it in the least costly manner, then there's a next best thing. And the security constrained economic dispatch tool tells you what the next best thing is. It solves the problem and presents that information to the dispatcher.

So we're going to do the next best thing so we can reliably serve the system.

(Slide.)

MR. OTT: So if we switch to the next slide, the next best thing is to move the generator at D, which is more expensive, it's a $30 generator, you move it up, and you move down the generator at Park City. By the way, I don't ski, but I like ski resorts. So if you move the generator down by 34 at Park City, and it's a $15 generator, so you're substituting $30 energy for $15 energy. That substitution is the cost of transmission congestion. Now we just simply have to translate that into something the market can use. That's really what this system is doing. The system dispatcher is very happy, because he sees I've made this action, I've made this move, and now I can reliably serve the 900 megawatts of load.

Now the market has to see the signal and understand the consequence. So what I think the best way to do is to look at the way power flows on the system and show you how some of these prices were developed. Let's look at the next slide.

(Slide.)

MR. OTT: If you're looking at the definition of what is an LMP or a locational marginal price, you're saying it's the cost of serving another increment of load or the cost to serve in the next increase in load. So if you look at Bus A, that's the bus where the Park City generator was connected. That's the one we were reducing for the transmission problem. So that generator now has room, extra room to move, meaning it's not loaded to its maximum capability. So if you would increase load at Bus A, you could serve it entirely from the generator, the $15 generator called Park City. So the locational price is $15, because if you did increase load a little bit, you would find that you could serve it all from that generator.

Now if we look at Bus B, you see that the price there is different. It's not $15 and it's not $30. It's something in between the two, and the question is, is why is it $21.14? Well, if you look, it's pretty easy. You say you take .59 times 15 and you take the .41 times the 30, you add those together and you get $21.14. And that's the simple answer. But I think there's more to it. Why did you pick those two numbers? And the answer is, what you're trying to do again is the next best alternative. The best alternative would have been to serve the load as we showed in the previous slide, but we would hit the transmission line too hard, if you will.

So the next best alternative is to say I'll serve that next incremental load at Bus B without increasing the flow on the line, but I also don't want to decrease the flow below the actual limit. So what you find is if you add one megawatt of load to B, you serve 59 percent of that with the generation at A or Park City, and you serve 41 percent with the generation at D, that ratio of flow pattern exactly balances the flow increase, or the incremental flow or the change in flow on the line E to D.

So if you take .59 from the one bus to the other, that puts a little bit of flow going from E to D, because essentially, the flow pattern on the system goes that way. But if you serve 41 percent of it from D to E, it creates a counterflow, if you will, to offset the flow that was caused by the cheap generator, if you will, going to the load. So those two actually maintain balance. They maintain balance on the congested facility. That's the best alternative. Because you can't serve it as cheaply as possible, the next best alternative is to serve it without increasing the problem but certainly without mitigating. And that's how you do each one of these. And the computer obviously does this automatically. It's very quick.

But thee point is is this is based on the actual flow patterns on the system and the actual generators being utilized to control the problem. So that way it translates this cost of redispatch to a set of prices you can see all over the system.

Did I help or hurt? Or any questions?

MR. O'NEILL: Since all of this network is in the Wasatch mountains, are these hydro facilities?

(Laughter.)

MR. OTT: It could be any facility that submits a bid and has flexibility to move.

MR. O'NEILL: Including hydro?

MR. OTT: Including hydro, yes.

MR. KELLY: Do you use a fixed set of thermal limits, or do you vary them seasonally or by hour or?

MR. OTT: Yes. The thermal limits on our system vary, essentially they can by hour. In our system, the way we do it is we have six -- each line has 16 ratings, and they're based on temperature, ambient temperature. So the system operator will say, you know, if it's 32 degrees out, he'll put the 32 degree rating set. And if it's 95 degrees, he'll put the 95. So they could change as often as he needs to change them.

Generally speaking, they'll change about four times a day. Now that's thermal limits. Voltage limits are a function of the voltage characteristic on the system. We calculate those every 15 minutes they get redone, recalculated, and that's dynamic. We'll talk about that later.

MR. MEAD: Andy, let me just ask one more question. Mechanically, you start out with a system that is unconstrained, and all of a sudden you observe a constraint. At what point do you actually start changing the prices? Do you do it right away or do you need some generator to react to a signal before you change the price?

MR. OTT: Generally, I should actually spend a little bit of time showing you. I went from, you know, a case where we were serving 900 megawatts of load and it was constrained. But what actually happens on the system is as the load is building, like pretend this is, you know, if you're earlier in the morning than this, and the load is still like at 600 megawatts instead of 900, the load will start to grow.

And the system operator actually sees that growing. He has tools that are running that show him into the future, and he sees the problem coming. And he says, okay, I see this problem coming. I can't let it go til it's overloaded, so I'm going to put into the software a limit at which I want to take action. And again, based on the rate of change of load, how fast the load is growing, how fast people are turning on the demand, if you will, he may choose 95 percent of the limit, because he doesn't want to get to 100. He wants to be a little bit below that. And again, that's based on certain criteria that he uses.

So he'll put that into the system, and the software will start to, as the thing grows, and it'll decide one five-minute interval -- it runs every five minutes -- that you need an action taken. So it'll send a dispatch instruction to the world more or less, the generators, saying that we have this problem and I'm ordering a redispatch action. And this is all done more or less automatically. He puts the thing in, we call it the unit dispatch system. It runs every five minutes. And it'll just suddenly become a problem.

When he sends that dispatch instruction, that's like an ex ante price, if you will. That's saying for the next five-minute interval, I see this problem coming.

Because he's working on a load forecast five minutes from now. He sends that signal. Then five minutes later, the pricing system will use that dispatch instruction and calculate an ex post price. So it's actually measuring the response of the generator to the dispatch instruction. So the generator responds and the price separates.

MR. MEAD: So the instruction is a megawatt instruction and not a price instruction?

MR. OTT: Yes. Either way.

MR. MEAD: But if the generator doesn't respond to the megawatt instruction, does the price change?

MR. OTT: No. If there's only one generator that's ordered to respond. To keep it in a simple case, if you ask a generator to move up and it was really the only generator to solve the problem, there was no others that could move, and he didn't respond, then the system will not see -- it'll more or less disqualify that generator because he didn't respond, and it'll say unconstrained.

MR. MEAD: I don't mean to drag this out too much, but what's the rationale for not publishing the price right away, and if perhaps there was some other generator that was out there that didn't submit a bid, the price could elicit that extra generation from that other --

MR. OTT: Right. Well, the point here is is that you're paying, essentially it's a real time performance monitor. So really what you're doing is you send out the dispatch instruction to request movement. The next five minute interval goes by, you measure the performance of the generator versus that instruction. If the generator responds, okay, he'll get in to set the price and the price will change. If the generator doesn't respond, then essentially he's not performing as you had requested, you aren't getting the services you were requesting.

Now what you'll see is obviously if that would persist, you would go after other generators or send more distinct instructions and other people would respond and you would get the price separation. But the point is is you're paying for what you're actually getting, and you're actually measuring the performance of the generator in real time, if you will. And we found it incentive-wise.

In other words, another way to do this would be to put out the price signal and price it as if he responded. But then you need some kind of penalty structure to incent response. Because he could just sit there collecting -- generators hate to move. They don't like -- generally speaking, they have a lot of inertia. They don't like to change, and you need to incent them to change. And if you don't put a requirement on them, you can't contribute to setting the nodal prices or the locational prices unless you move, then you have to come up with a penalty structure.

And again, we had opted, and we can talk about that again a little bit later in the detailed section or even tomorrow about incentive versus penalty. Does that help?

MR. MEAD: Probably for this part it does.

MS. FERNANDEZ: Let me go over -- I just want to make certain I understand all the numbers.

MR. OTT: Okay.

MS. FERNANDEZ: And we get the boxes and the circles right. On the first example, the only constraint in the transmission system is between E and D?

MR. OTT: Right. We just assumed in this transmission system that all the other lines had infinite capability, to keep it simple.

MS. FERNANDEZ: Okay. So all of the other numbers and boxes are the actual flow?

MR. OTT: Right.

MS. FERNANDEZ: Okay.

MR. OTT: Anything else?

(No response.)

MR. OTT: Okay. I think as far as covering, I mean, that's essentially how you get a locational price from a set of generator bids and a set of flow patterns, if you will, in the system. I'll probably leave it at that unless somebody has another question.

MR. KELLY: Andy, I don't want to ask a question to evaluate PJM, but just a factual question. The criticism is that people don't know ahead of time what they're going to pay for transmission. And I guess one is, are you going to get to that later? If so, I'll wait. But if you're not, the question is, can you describe how serious the problem is? That is, how much people are surprised in dollar terms both in the average case and the extreme case.

MR. OTT: Okay. And again, I think it depends on how risk averse you are. If you really don't like uncertainty, then there is a day ahead market where you can put in bids with a lot of different financial parameters around them, and we'll talk about those so I won't bother, to allow you to offset that uncertainty. So you have a day ahead forward that you can lock in both transmission and energy, and we can discuss that at that point.

And if you don't like the uncertainty int he day ahead market, you can protect that with the financial transmission rate. So there is a way to manage this uncertainty. So there is, obviously, in the real time system, you do have unforeseen events. But there is ways -- I mean, you have unforseen events. A generator could trip and change the energy price by $20 also and that has nothing to do with transmission.

The point is is if you're risk averse and you don't want to play the real time market, if you will, then you need to hedge. And again, these markets wrap around a lot of options for hedging. I'll talk a little bit later about how the day ahead market alternative allows you to lock in both energy and transportation and the same time to get away from that short-term problem. Does that help?

MR. KELLY: It does. But for those who play the real time market, what's some sort of typical and extreme examples of how much they might pay? If you think it's going to cost $40 for energy at a location but it ends up costing X because of congestion, is X $44, $80? What's X?

MR. OTT: It really depends on where you are in the system. Generally speaking, if you're talking about hubs or zones, larger areas, the price difference is less. You could have, at individual buses, you could have a very distinct separation, as much as, you know, we've seen price separations of hundreds of dollars. That's at individual substations.

Generally speaking, most people are doing business either at aggregations like we had talked about earlier where if you're serving retail load, you're not going to serve at -- you're going to have a zone or an aggregate that's load-weighted so that you can manage your risk, if you will, that way. Generally speaking, in aggregates and hubs and zones, you're going to see less of a distinct separation.

But very definitely, there are a lot of dollars involved in congestion. There's no doubt about it. I think congestion charges were in the $100 million range in PJM last year. So it can get significant and has gotten significant.

I think the good news is that in I think it was 2000 I had presented to our Energy Market Committee in the year 2000 we had very significant congestion in one area, and we actually were tracking that by transmission line. All those went away because they were fixed. And now obviously there's other ones now popping up. But the point is is at least you can -- it's sort of a causation. You can actually track the dollars to the constraint. And if a constraint becomes too many dollars, you can have some mechanism to get rid of it, whether it's the RTO jumping in and doing it or the market solving a problem, at least you can track it. It's not an unknown quantity.

MS. FERNANDEZ: When you said that the constraints were fixed, how were they fixed?

MR. OTT: New construction, adding or upgrading the line from 69 to 138 kV or something like that.

Okay. Financial transmission rights. Everybody needs a definition. So ours is on there. I'll let you read that. Again, the purpose of financial transmission rights.

I mean, you have a few different purposes. I have them listed there. The bottom line is, you may have a risk-averse entity who wants to manage risk. He doesn't like uncertainty. Financial transmission rights are a way to buy or acquire on a long-term or forward basis a protection from congestion.

It also facilitates forwards, because it allows people to trade risk or basis risk, price differentials across the system. And again, in PJM, we used this in the beginning and it's still in use today probably and we'll talk about that. It's a way to protect the firm transmission customer from the increased cost due to congestion. If they're paying for the wires, there's a way. In our case, we allocated the transmission rights to them and then they had the protection from congestion because they had actually bought the firm transmission service in our case.

The idea here is if you have mechanisms like financial transmission rights and you have the ability to do forward markets, risk-averse entities, the small player, the small municipality or the wholesale customer who doesn't really want to see the spot price, can actually stay out of the market completely if they do this. Now of course they can't win. In other words, if the market would go the good way, they wouldn't win, but they certainly won't lose and they won't have the risk of this huge payment.

And again, it really depends on your level of tolerance, if you will. But the point is, is again, we talked, the first slide, fundamental to any market design -- it's not PJM, it's any, okay? And that's the point is is flexibility. The market design has to be robust enough to present options, and I don't mean options in the sense of financial. I mean, participation options. If you want to do bilaterals, if you want to do the spot market, if you'd like to do self-scheduling.

You're a municipality, you have an on-site generator. And all you want to do is turn that on and serve your load, and you don't care who PJM is or why they're there. In fact, I was on the phone three weeks ago with a municipality who, they had been running their own generator, served their own load, and their prices had been high, but they didn't care. One down the street did care, but they didn't, because they more or less didn't see it. But they wanted to actually talk about selling their generator into PJM during when they had excess, because they saw the price going up, which is actually good for us, because that would create -- if the price is high, obviously we need that generator.

Now it turned out, it's only a 10 megawatt generator and may end up being a megawatt, but it's better than none. But the point was, was these people were in the beginning trying to be indifferent. Now they don't want to be as indifferent because they want to be a supplier. Obviously if you're on the short side, then maybe you may have a concern. Does that? I forget where we were on that. But I'll probably move on.

Characteristics of FTRs. I'll describe the PJM case. I may spend a minute or two on where we're headed. In our case, we have point-to-point transmission rights, financial transmission rights. They go from a specific source to a sink. Their megawatt level in our case is based on the level of transmission reservation. I'll explain that allocation procedure in a few minutes, where obviously their megawatt level is based on what the entity purchased.

They are financially binding. And this is where you get into the obligation versus option. Obligation means that if the price -- if the transmission right is worth money to you, meaning the price across it is positive, then you get money. But if it's the other way around, then you actually would pay money. That's called an obligation, because it's financially binding no matter what the price turns out to be, whether it's positive or negative.

There's also the idea to present options, which means if the price is positive, you get the money. If the price is negative, you don't pay anything, so you get zero

PJM is considering, we actually had contracted with a vendor to develop an option -- a computer program that calculates options for us. I personally am very curious to see how they price out. Hopefully we'll be able to run a mock option sometime in May to see how that goes. Obviously we'd like to try this out before we go commercial. So our participants will get a chance to play. If you're really nice to me, anybody can submit bids in a fake auction, so we could actually see how they come out.

But the point is is we want to see how these things price out. People are saying they want options, but if they don't price well, you don't know how they'll come out.

The other thing is, these are financial. In our case, the rights are not a physical right to deliver. Again, when you're back to market design, you have a lot of debate about physical versus financial rights. Remember the flexibility that you need in the market. If I allow you the ability to self-schedule your resource to your load and I give you financial protection so that you're indifferent to price, you have essentially the same thing as a physical right. But you have it in such a way that is complementary or doesn't contradict the reliability dispatch, the economic dispatch.

So you have a market system that the dispatch can use to operate the system, but also the financial side can get the equivalent of their physical right, because you have actually combined several different options in one where they can package them together. So you don't have to debate this, but you do have to say that the market design and the dispatch or the reliability management, the reliable management of the grid you should say should complement each other rather than contradict. And as long as you get that right, you can offer a wide variety of products, if you will.

MR. MEAD: Andy, could I just follow up on that for a second? The issue that PJM's FTRs are only financial. Would there be a disadvantage to allowing the holder to have a physical right which the holder could exercise or not, and if the holder didn't exercise it by scheduling day ahead, then the capacity would be made available to somebody else and their congestion revenues -- is there any disadvantage to that system?

MR. OTT: The disadvantage is in managing the grid, putting a physical right onto the system to actually -- again, remember when we talked earlier, I said we have the software, the security constrained economic dispatch software essentially is doing the same thing, has been doing the same thing for many years. We just opened up the process and made it transparent.

When you start to tie source to sink and paint megawatts, if you will, say that this is my megawatt and nobody else can have it and I'm actually trying to reserve physically some kind of transportation, then that starts to unwind and becomes less efficient.

So let me put it this way. If my system dispatchers down in the floor had to run around and track whose transaction was whose, and it's really not a physical -- it's not a piece of equipment, he's just tracking a contract -- it starts to get very inefficient, meaning he can't -- in other words, right now, today, the system dispatchers on our floor, they have generators, they have loads, they have transmission lines. All the contracts, all the contracts in the commercial markets are all overlays on top of that. They actually translate into the physical through the financials.

If you start to have the market contradict the dispatch, then you start to have problems.

MR. MEAD: I thought, though, that FTRs were only issued if they were in a sense physically feasible so I don't really understand why you couldn't tell the rights holder, all right, we've issued you an FTR, it's physically feasible, I want to physically transmit and I don't care what the congestion charge is. I don't understand why, why that would be messing up the operator.

MR. OTT: The point is the system operator, in other words, when you're tracking transmission contracts, if you track one contract, in other words, if it's just one from this generator to this generator, that's easy. But if you have hundreds of them, and again it becomes an efficiency problem in the dispatch too. To manage the system efficiently essentially you need to be able to move generation around and to try to say that this generator has to go over here, what has to be turned on, and there's no other option. In other words, if you think about it, if I dispatch a generator down to resolve a constraint, say that generator had bid $20 and the price now is $10 at that generator. What that means is the person who owns the financial right essentially can buy that energy at $10 rather than generate it at $20, so he's saving money but through the financial contract, he's still honoring his contract. But the rest of the market, I mean he gets more money than he would have had if he did is physical, so the rest of the market doesn't suffer as much. But if you force that physical in there, that price could go down minus 20, minus 30, minus 40 or whatever. The point is it would get much more dramatic and much less efficient, so you actually limit your options so you're actually taking away options to reliable operation. I just see that as less efficient than the other alternatives.

MR. HEGERLE: Andy, over here, the other side. How much of the load is covered by FTRs, and how much is wanting to get it but unable to get FTRs?

MR. OTT: Boy, that's a tough question. I'm not sure. It's hard to say how much of the load. You see, in other words, let me try to answer it this way. If you have load in an area and half the load is served by generation that you have in that area, okay, and the rest is served by remote generation and could be congested, then what's important to you is if you have FTRs from the local generation to load. That's less important to you. So the point is, it's the remote stuff. So to say what portion of the load, it's tough to say. I'd probably throw out 80 percent. I don't know, though; it's a very difficult thing to say.

Certainly as far as how many people want FTRs that can get them in our current structure, which we can talk about in a minute here, I think there is a shortage of

FTRs in two areas, and we certainly don't have enough to go around. Again, I'll throw out the 80 percent just because I don't have a better number.

MR. HEGERLE: I know you have some measure of options for that.

MR. OTT: We actually have plans in PJM, actually New York has a full auction of FTRs. I haven't actually explained how we do it yet. We'll probably talk about this some tomorrow. We think that's very positive, and I think our membership thinks that's the way to go because it will increase the availability of FTRS and, how should I say, get rid of hoarding if you will. I don't know, hoarding might be a strong word. But let me go through that.

(Slide.)

Obtaining FTRs. In PJM, we started out in '98. Obviously, when you're starting any new system, you need a way to transition, and in PJM our way to transition, if you think about these debates, I think they're all over the country, when you go to these kind of systems, who gets the rights is the big debate. In our case, in allocating FTRs, the network and firm point-to-point service, they're paying for the wires, they're paying the tariff rates, they're paying carrying charges for the wires. In return for that, they should get two things. Obviously the physical curtailment priority, if you will, the right to be served on the grid reliably, and the second thing is financial protection. So financial protection is in the form of FTRs. Obviously the curtailment priority means if you have network service, we'll serve you until we run out of generation.

If you look then the two other ways to get FTRs and PJM right now is the secondary market. That's bilateral trading. Let me give you some numbers. I think we had like 32,000 megawatts of FTRs allocated last time. At least it was that one year. I don't remember which year's which to be honest. About eleven percent of those are bilaterally traded. And then an additional 14 percent is optioned about. This is rough numbers. Probably the best place to look for these numbers I think is Joe Bowring's Market Monitoring Report. He actually produces these numbers, and I think he produces them by year. But our case is that we have a monthly auction that's really incremental above the allocated set. I think we are actually in committee right now to look at the annual auction concept. Obviously, the problem with annual auction is you have to figure out who gets the proceeds of the auction and try to figure out a way to manage the issue of revenue shifting, if you will.

In our case, we have a committee that I'm chair of called the Market Implementation Working Group. Any change to the market actually goes through that group before it gets up to Energy Market Committee and all the new members, so it's a stakeholder process. Right now, we're in the middle of a stakeholder process, talking about how we would transition to an auction mechanism. In other words, you auction instead of allocate. But then any time you do that, you have to figure out a way to allocate the proceeds. I won't go into that unless you have specific questions, but we are headed in that direction, and we'll see what happens.

COMMISSIONER BROWNELL: I have a specific question, Andy. You alluded to quote unquote allegations of hoarding in the early parts of the market. You also alluded to the fact that you learn as you go, and these are issues.

What advice would you have for us or for other markets who are developing on how to deal with the FTR issue up front?

MR. OTT: I think every definitely, it's very important that you have as liquid or as dynamic a market, healthy, if you will, robust market for FTRs as possible. It allows people again those options. If you are risk averse, and you want to be able to get to the FTRs, you need to be able to get there. So I think very definitely the ability to have a wide open auction for FTRs so that the players can manage the risk most efficiently is the best way to go. We do have to deal with the issue of, if you buy the firm transmission service or, quote, pay for the wires, then what are you entitled to. So it's the allocation issue. In

PJM again we allocated the FTR directly to them. In other areas, like New England, for instance, is looking at I believe allocating sort of a property right that allocates the revenues of the auction back to the people who bought the wires. But the auction itself is open. So really what you're saying is there's like a step in the middle and that's where PJM's, I think New York, I'm not exactly familiar with how they actually allocate the procedures of the auction, but they are very similar. New York's auction mechanism, where they have the flexibility of multiyear and those types of things is good. You need it to be as flexible as possible. That's the best advice I an give you.

COMMISSIONER MASSEY: I have a question too. How is it determined that there'd be 32,000 megawatts of FTRs?

MR. OTT: A transmission right is backed financially by the physical capability of the system. Meaning essentially that where you get the money to pay off the FTR is based on the physical characteristics of the system. It's how much it can carry. People submit, in our case, requests for FTRs, where they want them from and to. My engineers do analysis and they say this is how many we can award. So the 32,000 came out of that analysis so it's essentially an analysis of what the capability of the system can carry. It's very similar to like ATC calculations except that it's for FTRs.

MR. MEAD: One other question -- sorry, Andy -- can you explain a little bit more the difference between network service and point-to-point service in terms of what the customer receives? Is the difference mainly in what you pay, or is there some difference in the service received?

MR. OTT: I guess the best way to describe it is network service means you have load on the system, and you can serve that from anywhere in PJM or at the borders essentially at that price, meaning you don't have to buy, if you lose your source, you don't have to buy new service, so you can serve it from anywhere more or less. Point-to-point service, if you lose your source, you have to get alternative service because if you're serving it from our western border through to New York and somehow that goes away, and you want to know, okay, I want to get it from Virginia instead, you have to get new service because you're changing your source point. That's the biggest difference.

MR. MEAD: Are you saying that point-to-point customers are not allowed to buy in the PJM spot market if their source dries up?

MR. OTT: No. It depends on if you're buying from PJM to take it out of PJM. In other words, if you're exporting out, you essentially can more or less take it. You're saying, I'm going to source it out at the border point. In that case, then you really are buying spot to export, yes. But if you're taking it through PJM and it's point-to-point, you change your point and you have to change your service. In other words, there is a restriction on point-to-point service. The other point about network, essentially you're buying essentially the right to serve your load in PJM. For point-to-point you're probably through or out service.

MR. MEAD: Thanks.

MS. FERNANDEZ: I guess, can I ask a follow-up question? On the point-to-point, is it basically then because you have to buy alternate service that there's a built-in incentive to buy network if you can?

MR. OTT: If you're serving load in the PJM control area, obviously the scales are tipped toward buying network service. If you serve it with point-to-point, then you've got to figure out how you provide a balancing function. In other words, if you would buy point-to-point service instead of network, then essentially you're not technically part of the PJM control area anymore, you need to provide your own balancing function, you need to procure your own ancillaries, you know. There's a lot of things. You probably have to create your own NERC certified control area. Certainly if you want to manage your own pie, if you will, it's much more sophisticated.

Obviously, an alternative is to do network service, you know. If you have an on-site generator, just serve your load with your generator. Then if it should happen to trip, then you're backed by the rest of PJM. If you use network service, if you use point-to-point service, you're not. So it's very fundamentally different.

MR. MEAD: If you're a point-to-point customer, and your generator goes down and you're out of balance, suppose you needed to acquire balancing service from PJM at that point. Is that balancing service available at LMP prices or at some different price?

MR. OTT: I think it's LMP, but I think there's some balancing service fee that we put on too. But I've got to beg a little bit of ignorance. No one's ever done it, and it's buried in my memory. I'm sure it's in there. Really what it means is if you're saying you don't want to be part of the PJM control area essentially is what you would be saying if your serving load is point-to-point. So what you're really saying is I'd rather handle all this myself. No one has taken that option because essentially the firm tariff rate for network and for point-to-point are the same. The difference is the capacity, which we haven't gotten into yet, the capacity obligation.

The expense of creating your own control area, the logistical issues of getting ancillaries and other backup services, I think at this point has been too great for people to use the point-to-point option.

MR. O'NEILL: Would it be fair to say that the point-to-point option was designed to sort of satisfy the requirements of 888, and that you can get better service, uniformly better service by getting a network point-to-point?

MR. OTT: Yes. I think it's much more efficient for a customer to essentially be backed by the rest of the PJM market certainly very definitely.

MS. SILVERSTEIN: When you're dealing out FTRs in the first place, how do you know which of them are going to be network and which of them are going to be point-to-point?

MR. OTT: That's done by the request. In other words, the customers who have long-term firm point-to-point and network all come in at the same time with their requests. If we have to ration them, they're rationed pro rata based on megawatts, so if you have 100 megawatts of firm point-to-point and 1000 megawatts of network, and I can satisfy 90 percent, then you get 90 megawatts of firm point-to-point, and 900 megawatts of network. It's just pro rata.

MS. SILVERSTEIN: When you calculate the FTRs in the first place, you say I've got 32,000 megawatts I think you said. If you start with a fixed number of FTRs representing a fixed capacity, but then you have thermal line ratings reflecting ambient temperature and you also have daily changes in operational capacity of the grid, how does that affect the FTRs?

MR. OTT: When we do the long-term FTR allocation, we actually look at the summer period, so we would assume the worst case temperatures at 95 degrees. Actually when you're doing the long-term FTR allocations -- and this is probably consistent throughout the RTOs -- you're essentially looking at the stuff, the baseline I can serve all hours. That's why you have the monthly options and some of these others. During the new term, you can relax some of those assumptions and sell off the residual. That's how you do it.

MS. SILVERSTEIN: So if you are in say minimum load conditions, and you don't have an FTR, can you still shift?

MR. OTT: Shift?

MS. SILVERSTEIN: If the purpose of FTRs is to prevent you from suffering transmission congestion costs being curtailed, do you have to have an FTR for every single transaction that you conduct?

MR. OTT: By no means, no. In fact, the last bullet -- I see we're still on the slide somewhere -- the last bullet says it's independent of energy delivery.

Can I skip a couple of examples? I just want to point out the reason I only highlight this is there is a difference specifically between us and New York is the revenue adequacy of FTRs. What happens if you don't have enough.

(Slide.)

I've listed on this slide there are some times when FTRs cannot be fully paid out in PJM, and there are various reasons for that. Generally speaking, it's unforeseen system events. In our case, one heavy hitter for us, believe it or not, was something called "solar magnetic disturbances." Some people find it hard to believe that that actually can -- PJM I guess depending on how the ROCs, I guess there are certain ROCs in New Jersey that are susceptible to this, I don't know. But at any rate, they saturate transformers and what we have to do is go into conservative operation to make sure they're reliable. If that happens, you have assumed more capability on the system that actually is there for that specific period, so you've oversold the system, you're revenue inadequate. In our case, our FTRs are not fully funded, so if I can only pay out 90 cents on the dollar, everybody who has FTRs gets 90 cents on the dollar so it's sort of pro rata. I'll let them speak. Other areas actually fully fund their FTRs and they go get that extra money from somewhere else.

From a design perspective, it's probably better to have a fully funded product because then it's something that the commercial value can be assessed more readily. From that perspective, it's better but obviously when you have a short fall, you've got to get the money somewhere. It doesn't grow on trees, as they say, so you have to deal with the issue of allocation. So that's something we should probably discuss tomorrow rather than today.

MR. MEAD: Just briefly, do you have any sense of how often you are revenue inadequate?

MR. OTT: We have a lot of sense of that, yes.

(Laughter.)

MR. OTT: We actually publish numbers. Last year, we were deficient, we track it by month, but what really matters is the end of the year because if we're short one month and we have excess in another, the excess covers the shortage. Last year, we were $97.50 -- I'm sorry -- 97.5 cents per dollar. In other words, we were two-and-a-half cents short on every FTR. Again, the congestion charges -- don't quote me -- were like $200 million, and we were short $7 million. I think that's roughly -- don't quote me -- but two-and-a-half cents. And again we publish it, we actually use those as a performance measure for our engineers. In other words, what the engineer has to do is, he's trying to allocate as much of the system as he can without going over.

Again, you need to get the market, when you talk about incentives of the RTO, our incentive is to get out to the market as much as we can. The last thing you want to do is have $20 million of excess at the end of the year. Why would you do that? Essentially, you should have zero.

COMMISSIONER BREATHITT: Andrew, you talked about auctioning but you also talked about allocation and the stakeholder process is looking at some changes. Do you use allocations and auctions now?

MR. OTT: Yes, we use both now. We allocate the long-term FTRs based on who bought the service, and we auction every month to allow people to reconfigure and buy the extra FTRs that are available.

COMMISSIONER BREATHITT: So the secondary market is done, is it done bilaterally?

MR. OTT: It's both. We have a bulletin board system to allow people to advertise, to trade FTRs bilaterally. About eleven percent of the FTRs are traded that way. We also have a centralized auction which is executed every month. In fact, I think today we're declaring our FTR auction for next month. About 15 percent of FTRs are traded there.

COMMISSIONER BREATHITT: Is there merit in allocation versus auction? Is that's what's being discussed?

MR. OTT: Yes. I think the only method in allocation is it is a way to transition from no market to a market and deal with the cost shifting issues. But I think a better way to do it is to allocate the property right as a right to auction revenues. In other words, auction all the FTRs to the commercial market. Take the proceeds of that auction and give it back, whether it's load or transmission customers or whatever you call it, it's the people who paid the tariff rates. They are buying and product and what they're buying --

COMMISSIONER BREATHITT: Is certainty.

MR. OTT: You need a way to provide firm transmission service without increased cost. That was our design paradigm when we allocated FTRs directly. I think there's another way to do it. It is a little more complex, it does require the load to be a little more sophisticated, but it does open up the ability.

If you think about the New Jersey BGS auction, that auction would do much better if there were a more vibrant market in PJM for FTRs because the people who want to come in and be an alternative suppliers are very nervous about serving into New Jersey right now because they can't buy long-term FTRs on a forward basis because there isn't a mechanism right now to do that.

COMMISSIONER BREATHITT: So allocation has merit in that example?

MR. OTT: Actually auction would have merit in that example because it would open up the ability. Allocation has merit as a way to minimize revenue cost shifting, but you can have both. You can allocate the property rights as proceeds to the auction, then auction everything. So you can have both. It's a two-step process.

CHAIRMAN WOOD: Let me take that New Jersey example. Say we're a small retail serving a mixture of residential and commercial load in New Jersey, and I didn't own my own power plants or maybe owned a couple but not equivalent to my load. Tell me kind of from step one on the whole FTR issue, what do you do? They come to your market, they want to sell to this handful of customers.

MR. OTT: And you say they have on-site generation?

CHAIRMAN WOOD: They might have some generation in central Pennsylvania and central Maryland, distant from their customer. Also let's assume that they don't have the equivalent generation so they're going to have to buy some off the market.

MR. OTT: If they have some generation, obviously they're going to bring to the table -- I'm assuming they'll buy network service -- and they're going to bring to the table capacity resources. So when they do that, they're buying network service. They have capacity resources. That entitles them to request FTRs under the allocation procedures we have today.

CHAIRMAN WOOD: So the capacity resources would be equivalent to the peak day demand of those New Jersey customers in say the summer?

MR. OTT: That plus 15 percent or whatever. So they would come in and request FTRs from those capacity resources to the load, so they would go from their generator location to the load. Obviously everybody else is requesting those too, so they may get some percentage of those that they requested. But they also, there may be generation locally that is not outside of that area that they may contract with also. Say they have a mixed portfolio, if you want, but they would go after the valuable FTRs, the ones that were distant where they would perceive they would have economic value during times of congestion, they would go after those and the allocation procedure. They would also bring to the table maybe other capacity resources that are local.

So when it comes time to serve the load then, they now have some measure of protection against congestion in the form of an FTR, so then they have to make a choice. They have to decide do I want to play the spot market or do I want to lock in forward energy, so even though I don't own a generator, I could go contract on a forward basis to purchase energy on a monthly basis or whatever. That way, they could become somewhat indifferent to spot price. That would be one option. So totally try to cover your own resources with either your own generation or with forwards. The other option would be to do that for 80 percent or 90 percent and then play spot. Then you have two options in that case. You can do the day-ahead market in PJM or you can do the real time. That really is your choice.

Or you could change that but the point is you would, as a customer, since you had these options, can decide how much of your load you want to risk serving spot. You don't have to serve any necessarily from spot providing you buy it by the forwards. The only issue you'll have then, depending on how many FTRs you have versus the load you have to serve, and if you didn't get enough, for instance, then you have a problem.

CHAIRMAN WOOD: Do you all settle in PJM based on profiled load for your states that are opened up for active residentials?

MR. OTT: Yes.

CHAIRMAN WOOD: What kind of variance do you have from actuals with profiled load? A couple percent, ten?

MR. OTT: I don't know, I'm not sure. I honestly don't know.

CHAIRMAN WOOD: I was just wondering because the inaccuracies --

MR. OTT: I could try to get that number from somebody else.

CHAIRMAN WOOD: If you don't know it probably hasn't been an issue then with your retailers in these new markets?

MR. OTT: I don't think so, no.

I think in general, profiling hasn't been a big issue. I can try to find out.

MR. O'NEILL: My understanding was, PJM doesn't settle on profiled load, they settle on actual load. In other words, you calculate the LMPs based on the actual dispatch, and those are the prices the buyers and sellers --

MR. OTT: I thought he was down one level below the wholesale to how they actually interact with their customers.

CHAIRMAN WOOD: The wholesale settlements are done on actuals.

MR. OTT: Yes, I'm sorry. They actually get reconciled. In other words, the day ahead market puts a certain load distribution in there, then the real time market has the actual load distribution, as described by our state estimator. Well, then, there's a 30-day and a 60-day reconciliation that actually trues up based on meterings. I thought you meant down one level below that.

CHAIRMAN WOOD: The reconciliation between the wholesale and his customers.

MR. OTT: I'm sorry. I totally took you in wrong.

MR. LARCAMP: Over here, the big guy with the beard.

(Laughter.)

MR. LARCAMP: Can you just clarify for me where the FTRs go? They don't go directly to load. Do they go to LSE?

MR. OTT: To transmission customers.

MR. LARCAMP: To the wholesale transmission customers?

MR. OTT: The person who is taking transmission service from PJM. So whoever is buying the network or the firm point-to-point from PJM. It could be a load aggregator on behalf of a set of customers that he's gotten together. It could be an LSE. It could be the EDC. It's whoever is buying the transmission service.

MR. LARCAMP: And that is periodically updated so that as the usage changes, the FTRs will change, based upon who's on the system?

MR. OTT: Yes. Every year we reallocate based on who -- you know, people come in with a brand new set of FTR equipment.

MR. LARCAMP: And in responding to the Chairman's example, is there a weighting given to people that are serving load with local generation?

MR. OTT: No. If you're serving load with local generation --

MR. LARCAMP: You talked about local generation in response to his question.

MR. OTT: Well, the reason I differentiated it was, that if you have local generation, it's less likely that you need to protect the delivery from that location generation against congestion, because it's sitting very close.

MR. LARCAMP: But I've used the system, so whatever congestion was on there, I would get the FTR?

MR. OTT: If you wanted an FTR.

MR. LARCAMP: I've paid for it.

MR. OTT: Yes. If you wanted an FTR for local -- like if you have a generator that's sitting very close to the load, the FTR either has no value or very little value.

MR. LARCAMP: I might auction it, might not buy it in an auction, but in terms of allocation?

MR. OTT: You could have it, yes.

MR. LARCAMP: If I'm using the system, I get the pro rata share of the allocation merely because I bought network service, right?

MR. OTT: The allocation of the FTR, yes. But its economic value, because the two points are very close, may be zero. But you could have it anyway. You're getting something that may not be worth anything.

MR. LARCAMP: But I'm not paying for anything until we settle at the end of the year, how close you got to 100 percent. I mean, I'm paying for that in my network charge.

MR. OTT: Yes. But remember, the allocation of money to you as an FTR holder is driven by the FTR's economic value, as compared to the day ahead energy prices. So if you have a generator and a load on the same location, then it would always have the same price and its value would always be zero. Now you could have that. It's like having something on your books that takes a line item that's always zero. And most people don't opt for those. They just don't take them.

MR. LARCAMP: They don't take them if they're allocated for free?

MR. OTT: Yes, because they're worth nothing.

MR. LARCAMP: Okay.

MR. OTT: Now if you have one that's two or three buses away and you think it may be worth something, then you would take it. But in this case -- remember, there's downside and upside risk because it's an obligation.

MR. LARCAMP: Right.

MR. OTT: So having something on the books that could be positive or negative, when it's very close together, is probably -- people would say, well, I don't see a long-term economic value, so why would even take it?

MR. LARCAMP: So even though my downside is minimal, because there won't likely be congestion within, if you will, the load pocket, because my generation and load are both within the load pocket, people will turn those back, and that's the source of the auctioned FTRs?

MR. OTT: No. Those actually don't really -- remember, since they're close to each other, they really don't consume space on the transmission system. In other words, they're almost like irrelevant. In other words, you're serving the energy because you have network service.

Remember, you get two things with network service. You get the right to serve it, I mean, the physical curtailment priority, and the financial protection. Since your generation and load are both local, you really don't need financial protection for the transportation. I mean, you're allocating, and you certainly could get it, okay?

But it doesn't utilize transmission, a scarce transmission resource, if you will, because they're right next to each other, and it really has no economic value. So it's really up to you as a customer. So then the last of your worries is transmission congestion at that point. Your big worry now is serving your energy on a forward basis.

MR. HEGERLE: And the reason you're saying that they're worthless to others is because they're path specific?

MR. OTT: Yes. They're beside each other.

MS. SIMLER: Andy, going back to what you had said earlier about PJM looking at options, in this case, if the generation went off line that was serving that local load to the customer had taken the FTRs, and had service from elsewhere, would they be in then in a position of paying?

MR. OTT: Again, probably not, because if they took the FTR from that local generator to the local load, since they sit right next to each other, no matter what happens on the system, those two prices are probably going to be the same.

MS. SIMLER: But from a couple of locations away?

MR. OTT: Oh, yes, then it could be significant.

MS. SIMLER: Thank you.

MR. OTT: In that case, then you might want to take them. If they're a couple of buses away.

CHAIRMAN WOOD: Andy, on page 20 of your presentation. It's the little page, the little number. It's a slide you've already done. There's a footnote there that says FTR sources and sinks can be single.

MR. OTT: Yes.

CHAIRMAN WOOD: If you were a retailer and you did a deal with a generator that had several plants and you don't really care which plant does it, you just want it to be to you at the lowest cost, what kind of -- and just say they're nonaffiliated parties so they're both going to be trying to maximize their own financial benefit -- who gets the rights in the first place to FTRs? I mean, traditionally in the PJM market. Is it the LSE that's getting them or does the generator get them?

MR. OTT: Generally speaking, it's the LSE who buys the service, so it's the LSE. But, again, in this market, if the generator would sort of sell sort of a delivered product and the generator would decide I'm going to go buy on their behalf the network service, the generator themselves could actually in this market get the FTR if they were the transmission customer from PJM's perspective.

Again, it really depends on the contract between the two. If the load says I'll take care of the transmission serving stuff; I just need you, the generator, for energy and capacity, then in that case, probably the load would get it. But if the generator wanted to be like a full service supplier, if you will, and come out and actually buy the service, supply its own generation, its capacity, it could do that also.

I hate to -- again, the market is set up so that --

CHAIRMAN WOOD: Either way will work?

MR. OTT: Yes. There's a variety of options.

CHAIRMAN WOOD: Are you seeing much of the latter, where the generator is providing kind of a balanced portfolio of service?

MR. OTT: I think it happens. I'm not sure it's the dominant. I think generally speaking, load aggregators come in and fill the niche between them. But I think it can happen, or I think it has happened. I'm not sure it's widespread. And again, I'm not sure why. It's probably the fact that generators do better at generating than they do at managing.

CHAIRMAN WOOD: Well, that footnote there just raised a question in my mind if there was much of that going on. So the FTR sources and single nodes, how many are there in the PJM system right now?

MR. OTT: Single nodes? Twenty-two hundredish, something like that.

CHAIRMAN WOOD: And then when you say aggregated points, such as hub zones or aggregates, that would just take a number of single nodes and say we're going to treat these as one?

MR. OTT: Right. Exactly. Like say a wholesale customer has, you know, ten locations it's serving in the Pico like Philadelphia area, it can define an aggregate or ask us to do it for it, whichever, and only really track the price at that aggregate, which is essentially a combination of ten prices. Then we just post that price for them. They have to do node calculation. They can just track that one point, even though it reflects ten locations. So it just simplifies. And then their FTR can be to there. And they can just track that price on our system. So they don't have to worry about the fact that there are those ten, and they don't have to do the aggregation.

Again, the point on all that is, if you add that layer, what I call the commercial layer, so you have the operational layer, which is you need the physics of the system, you need the consistency between operations and the market. Then you have a commercial there that translates that into what the market needs to work. And in our case, even in our systems we actually do have -- our EMS system is the physical layer. Then we have a transitional layer between that and markets. So when people ask me to add a new hub -- you know, we had talked about that I think before you came in -- it's just like a day or two. Okay, you add a new hub. I define what the hub is, I put it out to the market and it starts posting. Because you have that separation for modularity, if you will. And I know we aren't talking about software design today.

But the point is is you have to, when you're conceiving how you're going to design the market, you have to make the systems similar. That's why you have this aggregation capability, is because you have to -- the market has to be able to withstand more or less a lot of different commercial --

CHAIRMAN WOOD: How often can a customer change its source? I mean, I guess the customer probably wouldn't change its sink too often. But, I mean, there is an annual nomination process that went to allocating the network service FTRs.

MR. OTT: Oh, they can change the capacity resource every day if they want. There's some downside to that. Because if you have an allocated share and then you change your source, you essentially surrender that FTR and you would have to go back and request a new one from your -- now if you do it at the same time, the likelihood is you'll probably get it, because you're just --

CHAIRMAN WOOD: Request a new one from your --

MR. OTT: From the new resource. In other words, if you have a brown generator, okay, that you got, you had when you did your allocation in the annual, then you switch that over to the green generator tomorrow, well, then, you lose the entitlement to the FTR from the brown one because you no longer have it.

CHAIRMAN WOOD: Right.

MR. OTT: So now you have to go ask for one from the green. And if you do that on a daily basis, there's a risk that somebody else will come in with a request before you. They'll be switching also and they'll use up the capability that you just surrendered. So you can do it on a daily basis. It's more likely that you would tend to be a little more static than that. But then that's just a commercial issue. I mean, obviously in the system you can change it daily.

MS. FERNANDEZ: I was wondering if we've come to a point --

MR. OTT: Break?

MS. FERNANDEZ: Yes. I was thinking this might be a good time for a 15-minute break.

MR. OTT: I have to recover.

(Laughter.)

MS. FERNANDEZ: We'll get back together at 11:15.

MR. OTT: Thank you, by the way. Very nice questions. Appreciate it.

(Recess.)

MS. FERNANDEZ: Could people start heading back to their seats?

(Pause.)

MR. OTT: Okay. We're going to start. Boy, I can say anything now. I think probably the best place to start, I think we've covered the FTR, so I think now we should talk still on the overview of the day ahead market.

I think if you look at the PJM day ahead market, it's much more than just a simple forward where you're matching bids and offers.

(Slide.)

MR. OTT: It allows you to lock in, in addition to energy on an hourly forward basis, it also allows you to lock in transportation. And that's sort of fundamental, again, to this concept of being risk averse against a real time spot, the real time uncertainty.

So the day ahead market allows you essentially to lock in. It is fully financial, meaning it is just a financial look at the system. But it is also, as we'll find out, physically feasible. So people are putting in their financial positions. Some of them may be real generators. Some may be real loads. Some may be financials. But the point is, we're actually doing the power flow analysis. You have the reserve model, so it is a physically feasible model also.

If you look at our day ahead market, and we can go to the next.

(Slide.)

MR. OTT: It is based on the hourly quantities that are scheduled. They're scheduled by the participants. The participants will put in bids. The same thing applies, as we had said before. You can sell schedule. You can purchase spot. You can do bilaterals. That's all the same concept. The day ahead market is the same as the real time. You decide as a participant which way you want to participate. What you're really doing here is you're locking in what you want to deliver or what you want to protect for tomorrow.

Then you have the real time market which is settled based on differences between the actual deliver and the schedule delivery day ahead. This sets up a feedback mechanism. Obviously you have two different markets, two different prices. They will converge. They're going to be made to converge by the participants who are trading. Obviously, if you bought energy day ahead yesterday at $40 and in real time it's serving at $25, tomorrow you may rethink the decision to lock in a lot of stuff forward at a higher price. So that tension, if you will, or ability to arbitrage or convert to market is positive.

(Slide.)

MR. OTT: If you look at the next slide, just so we understand -- again, I'm not going to go through this in detail -- if you lock in at a day ahead price, then essentially, and you deliver -- so if you lock in 100 megawatts, you pay whatever the day ahead price is. If you actually deliver 105, you're only paying for the additional five at the real time spot, the real time price, I should say.

So the point is, is you are somewhat indifferent for the 100 megawatts to what the real time price has become. You only care about the differential. That's very important obviously if you want to lock in at a forward or known congested price. And there are various mechanisms which we'll talk about later in the market to allow you to do that.

(Slide.)

MR. OTT: If you flip to the next slide, you have the generator, and I went the opposite way for a generator. I said he locked in at 200 megawatts and got paid the day ahead price. Remember, the day ahead is financially binding. It is a contract. So when he delivers only 100 megawatts in the real time market and the price is higher, he actually buys back the energy he didn't deliver at the higher price. And again, the incentive then is that obviously that would cost him money, the generator obviously would want to deliver as scheduled, but for some reason can't. Could be some physical problem.

(Slide.)

MR. OTT: So if you look at the next slide, this gives you the implications. And what this shows is if you have a demand scheduled or a supply scheduled, you could either pay or get paid in the real time balancing depending on your position in the market. So the tradition where load pays, generators receive sort of breaks down when you go to this kind of balancing market. It depends on what your forward position is what you look like. And all that really does is allows the market to have more flexibility, and that's really what we're all about.

MR. MEAD: Andy, let me just jump here for a second. I understand that PJM also allows entities that have bilateral contracts or sell scheduling not to bid for energy but either just nominate a physical quantity of transmission between a source and a sink, or there's also the entity can bid for transmission, submit an up to congestion bid?

MR. OTT: Yes.

MR. MEAD: How much -- how popular is the up to congestion bid? Are you finding very many people submitting such bids?

MR. OTT: The way you think about is probably a little ahead of where I wanted to talk about up to congestion bids, but I'll just say that I think it's grown in popularity. I think when we first started it, it was not understood.

I'll say this now and I'll beg forgiveness to explain it later. What an up to congestion bid, what that is really saying is I'm going to bid a price differential in the day ahead market. That's an hourly financial transmission rate. So, if you remember, your financial transmission rates, you can buy month ahead or get them year ahead in allocation. You can buy them daily, you know, get them daily by trading, but there's really no hourly transmission rate.

The way you get an hourly transmission rate is to bid into the day ahead market, these differential bids. And so it really completes the hedge path, if you will, and produces that hourly hedging product for transportation. I'll just leave it at that. And to be honest, its popularity has not been as great as I thought, but it is growing, so I think people are starting to understand its usefulness.

I've obviously been trying to sell it because I think -- and again, I don't care whether they use it or not, it's just another option.

I'm going to switch gears, then, to the ancillaries. I have some comments on ancillaries, probably fly through it fairly quickly. Again, the real stuff that people are -- and this is again my viewpoint or our design philosophy, if you will. This is probably more PJM-specific than anything I've said so far. Most of what I've said so far has been more generic I think.

More or less, energy is what's locked in or transmission. The ancillary services are stuff that we, the

ISO, need to make the market function more or less. In other words, somebody buying energy is buying something consumed. The fact that we need spinning reserve or regulation on the system is more for our benefit to reliably serve the system. That's just my thought on it.

So, really, what we're trying to avoid or what we've been trying to avoid in these markets, is we don't want the -- and I think we've seen this. We've seen examples of this where there's distortion where you have the ancillary products start to distort the main product. And I think that is a design philosophy we're very concerned about that. I won't use the word "petrified", but I personally, you know, have a lot of concern when we go into these.

(Slide.)

MR. OTT: If you go to the next slide, I think, again, the real time market, it's very fundamental that real time -- and I think this is probably a point of agreement across most of the markets as they're going to develop -- in real time, you really need to co-optimize or simultaneously optimize these products.

In other words, you need to have energy, obviously transmission congestion, regulation, spinning reserve, all that stuff has to be handled in the real time market when you're getting right to serving the load. That has to be handled in the most efficient manner possible.

And I think that you certainly need to do that simultaneously.

I think that's the most efficient, having the separate markets for regulation and spinning reserve I think are going to be a standard. I think PJM has been slow to do this, but again, it's absolutely fundamental to us that the energy market and the energy market incentives remain strong and people have confidence in those. To the extent you can add the ancillaries in to have markets for them and have the efficiency for them, that's great. And for us, we added regulation last year and spinning is on the way.

And I think those will actually develop, and you'll see those as a standard. But I think the product substitution problem is something that we can't ignore. The fact that these products are interrelated, and substituting energy for regulation or spinning reserve develops a lot of uncertainty in the real time operations.

In PJM, we thought, again, to stay with the philosophy that you don't want to distort the main product to provide these others, we dealt with the product substitution problem using the lost opportunity cost approach. And I may cover that later. We found that to be very, when we put our regulation market in, before the market went in, we didn't have enough regulation. We were short almost every day. We put the regulation market in, we haven't been short a day since. The regulation prices didn't go up substantially versus what they were under the cost world. So it was sort of for us it was a measure of success.

And we think a reason for that success was essentially you added another product. You didn't want to add it to increase necessarily the cost to load, but you wanted to add it to develop a more vibrant supply. You wanted to send the right incentives. In other words, you want to incent generators to add that kind of equipment because they can sell it as a separate product. But you didn't want to do it in such a way that it would cause distortion or unrealistic results.

So the lost opportunity cost concept was to say, if I walk you in forward for energy and I ask you in real time to forego that energy contract and provide reserve for me, meaning back off your generator, even though the economics in the energy market say produce it, we're saying we'll cover you for that because the market now needs the regulation. It's more valuable to us. And the way we actually translate that product substitution decision to you is we cover you for your lost forward.

In other words, if I locked you in $30 forward for energy,t he energy price is now $33 but you're more valuable to me, the RTO, as a regulating unit, so I ask you to not serve the energy at $33. I'll cover that differential for you so that you, the generator, aren't absorbing risk. If the generator is -- generally, generators, believe it or not, are risk averse. News flash.

The point is, is they don't want to have to deal with that uncertainty. If they do, they're going to add a risk premium on it. And again, this kind of design allows you -- it really takes you a step back and says what is my goal? What am I trying to accomplish? And in our case, we were trying to accomplish a vibrant, real time market that efficiently procured these products. And that's really where we went. And probably we'll discuss that a lot in detail tomorrow and I'll probably beg your forgiveness to leave it at that.

MS. FERNANDEZ: Actually, may I ask you question?

MR. OTT: Oh, no. Yes.

MS. FERNANDEZ: Hopefully short. Could you sort of explain or sort of say why you thought the regulation and the spinning reserves were the two markets that you could have as separate products as opposed to the others?

MR. OTT: Well, I think those products are more standard in the sense of every area needs them to serve, to meet the reliability criteria, the NERC standards. Other ones like nonspinning reserve may be more area-specific.

Give you an example. In PJM we have so much spinning reserve that nonspinning reserve is not really that useful to us because we have so much ability -- there's a specific type of device called a synchronous condenser, if you will. It's a certain type of generator that can provide spinning services to us. So for us, it just isn't an issue. In other areas, though, nonspin may be an issue.

I know in New England they're going to add as part of the spinning reserve rollout that they're doing as part of the standard market design implementation they have, they're actually going to add as part of a special tier two spinning resource to nonspin.

So, I mean, I guess the reason I was saying that was -- and then the operating reserve, the lower level reserves, again, for us that constraint is never binding simply because we have so many of the short-term combustion terms, stuff that can start so fast. So it never is something that we hit a lot.

Again, you can have regional differences. I don't think spinning and regulation fall in that category. I think you're going to need that no matter what.

MR. MEAD: Can I follow up on that for a second? You said before you started having a separate regulation market and paying opportunity costs, you sometimes developed shortages of regulation service. What about ten-minute spin? Are you paying opportunity costs for generators that are on spin now?

MR. OTT: Yes. We have like a cost-based type market today for certain classes of generators to procure spinning services. The roll out of the spinning market will, how shall I say, increase the supply side of that. It will allow more generators the option, it will allow like steam generators to build and to move down and to be paid to providing spinning. So the design will essentially mirror the regulation. In today's world, it's a very narrow -- it's not really a market, it's a cost-based type procurement. Does that help?

MR. MEAD: When you say cost-based, does the cost include opportunity cost?

MR. OTT: Yes.

MR. MEAD: Okay.

MR. OTT: The new market will be much more dynamic of course. Let's see, ICAP. Let's spend a little time on ICAP.

(Slide.)

MR. KELLY: Could you spend 30 seconds of how you provide reactive power from generation? Is there a market for that if the generator is called upon to provide it because of the system opportunity needs it? What happens?

MR. OTT: Essentially, PJM essentially reactive services are more or less a FERC file. They file more or less generators. When I say, they, they file, the best way I can describe it is a rate to provide that service for those functions. Essentially, when a unit is designated as a capacity resource in PJM, that means it's accepting essentially a contract voluntarily, if you will, to provide certain services to PJM. Part of that is a certain voltage performance standard, and again I think today in PJM, or actually how shall I say making those more sophisticated, I think our next evolution is to nail down a little bit more of that voltage performance. Decide if we need some kind of performance, either incentive or penalty, on voltage analysis. We have seen somewhat of a degradation in voltage performance in PJM and we're still investigating. We actually have a committee. I described our committee structure. There's the MC and others underneath it who do more detailed work. One of those is to investigate that but for now it's just still more or less command. We are asking for this service because you're a capacity resource, period. There is no market-type mechanism. And to be honest and reactive, we can debate that. But markets for reactive are going to be tough.

(Slide.)

I think if you look at probably the concept of ICAP in PJM, we have the ICAP requirement. It's really to look at long term generation adequacy and short term availability of generation. Again, ICAP resources are required to bid into a day ahead market. In other words, if you voluntarily accept money for being an ICAP resource, you have to be available to provide that. Again, this all rolls together with my previous slide, which I didn't really cover, which talked about the ancillary service market where I said, you know, the product substitution issue, if you deal with that in the real time spots, you have a real time simultaneous system to procure reserves.

In our case, we're saying we don't think it's any more efficient to lock in, you know, have a day ahead market that locks in all their separate products. If you deal with a product substitution problem, we've lost opportunity. Then that deals with substituting the forward contract with the real time product. So if you keep that simple, so you don't have multiple product substitution decisions to be made, you may find it's as efficient and maybe doesn't have as much interaction with the real time market. That's really our philosophy as we were going forward. Again, that's going to be debated for a while I think. I think that concept is something we have to come to, but I think in reality if you look at it, whether you lock in the reserves on a forward basis or not, you're both doing the same thing. In other words, you have a day ahead market that has the physical restrictions that says you have to have enough reserve and you have to have enough transmission to serve the system reliably based on the day ahead schedule. When you roll in the ICAP requirements, since those generators are getting money for installed capacity payments, and that's voluntary, they don't have to do that, they have responsibilities, and those responsibilities are you have to be there when we need you because you're an ICAP resource because you've got that money. So in that case, when we don't schedule them day ahead for reserve, they still have to be there in real time if we need them. So we've already paid them to be there. We don't have to pay them again to lock in forward, and that was really the concept, so the two interact. The ICAP and the day-ahead forwards do interact.

(Slide.)

Probably if we go to the next slide, some of the obligations for ICAP, I've already talked about that, but I think the last thing is the recallability. If you sell

ICAP, that's a capacity project, to PJM, so it essentially converts to PJM can recall the energy during times of system emergencies. That means you can have a generator that's sold ICAP to a PJM customer. They can take the energy though and sell it out of our system. They can sell it to New York, they can sell it to Ohio, whatever. But if PJM is short because we have that ICAP contract, we can recall it. The reason is of course they got paid money to be there when we needed it. If we don't need the energy, they can do anything they want with it. Again, that was just some of the restrictions on ICAP resource. It's like a call contract on energy, if you will. It's like we're reserving, our customers are reserving these generators for times of system shortage. And most of the time, you may or may not need them, depending on the type of generator. That's pretty much all I was going to say on ICAP. Any questions?

MR. KELLY: Andy, the customer buys, besides a contract with a generator for ICAP, if there's a shortage, is the shortage associated with the customer and that customer's generators are called on, or is it a system wide shortage, and how do you determine which generators to call on?

MR. OTT: In PJM essentially we're looking at everybody brings ICAP to the table. It's sort of the percentage above your peak load and resources are designated as ICAP. When PJM has a capacity emergency, part of the whole concept of this market, since it is sort of an open transparent market, is we aren't painting megawatts. I'm not saying your megawatts in the energy market when we're in real time belong here or there necessarily. It's just all the generation megawatts I have are available to the system operator. The financial contract, which is capacity, is outside of that. We know if the generator is designated as capacity or not, so the point where I'm having a capacity emergency, when it comes into the recall, I'll call those generators back in, or cancel those contracts going out. And I'm not really tracking who's short or who's long in the allocation in other words. If I have to purchase emergency energy, meaning I ran out of energy, then I will allocate those to people who were short.

MR. KELLY: But you don't call on all the generators if you only need a small percentage of them. How do you decide who to call on?

MR. OTT: I am blank, I'm sorry.

MR. O'NEILL: When there is a capacity emergency, you've run out of most generators bidding into the market, so you have to go and call other generators back. Up until then, you're calling people in merit order. But when you have a capacity emergency that, by definition, means you've run out.

MR. OTT: I'm trying to remember how we call, and it's blank. It'll come to me. I'm just blank. I'm sorry.

MS. FERNANDEZ: Do you end up recalling generators very often?

MR. OTT: When you talk often, a very small percentage of the time. Generally we have capacity events, I think last year was like 12 hours I think. I'm not positive though, I could be off. But it's a few hours type stuff. It could have been more than that, I just don't know.

Let me switch gears, and if I think of that, I'll come back by the way.

COMMISSIONER BROWNELL: One more question. Is it fair to say that the ICAP concept is a work in progress now in PJM based on market experience? In fact, I think it's been at least through one iteration in terms of rules. But would you care to once again give us some advice on where we might need to go or some of the concerns that have been raised about ICAP to date?

MR. OTT: I think in general, I say in one of my slides, in theory, ICAP's not needed, meaning the market will take care of it, and if there's a shortage of it, price it. But the whole concept of energy or electric energy has become more of a privilege, so going short isn't necessarily an option. So I think capacity, for practical purposes, in absence of demand response and some of these other things, capacity is necessary in the short term. And I think the idea of designing a comprehensive capacity solution, I think some of our capacity problems are probably due to some legacy in some of the history of what's happened. Some of the incentives were a bit messed up. Of course, you could go short for a day and only pay that daily shortage, so you could actually, I won't call it gain, but the incentive of the market wasn't as good as it could be. So I think when you're looking at dealing with capacity, you really need to look at the capacity market in the sense of converting it to some kind of more standard, like a call or something like that, something more standard.

In PJM, our scarcity price if you will, a thousand dollars, that's the price cap, so it could be converted to some kind of call at that price or something like that, but something more standardized across the system so people understand it. I think the other issue is the demand side. I think that's critical. Again, the reason you have capacity requirements is because you really can't afford to go short. The other option of course to increase the supply of capacity is obviously you have demand response being a capacity, so I think those areas and I think that's where we're headed, we have an initiative, I think. It's across New York, New England and PJM. I'm not sure, to actually try to redesign the capacity product across the markets. Its stakeholders from all over and to be honest, I can't impart a lot of wisdom to them or to you necessarily except I think there's more to the subject than just dealing with the generation.

COMMISSIONER BROWNELL: I commend the efforts of those who are trying to solve this. And we've heard from I think every participant in RTO week, and I suspect in the next couple of months, we'll hear the demand side is important. Yet, on the other side, we hear that there's some resistance to the introduction of demand side solutions, particularly from incumbents.

Do you want to comment on that?

MR. OTT: When you're adding the demand side response in I think some of the issues have been, there is the jurisdictional. Whose, quote, customers are they. How does it interact with AOM and some of these other issues? Some of that can be worked out. I think some of the other things you hear though is how much are you subsidized or socialized, if you will, whatever the bad word is, to actually incent this response. Obviously traditionally, you're going to say if the price is too high, you won't consume. We've said, well I think a lot of the models out there are saying, well we may need to pay people instead of just letting them save money, we may actually pay them not respond to get the thing moving, and the issue, when you pay them not to respond, somebody has to get the money from somewhere. And I think the concern all along has been how that works.

I think a little bit of socialization is probably okay, but I think as the transmission congestion thing has shown, if you have a little bit of socialization, everything's okay, but you can't control it. If it goes nuts, then you have something that happened in PJM when we did the MCP versus the LMP. You've got a lot of socialization and you couldn't control it. I think some people are scared of that in the sense of do you have to design it if you are going to pay extra to get the response, you have to allocate the costs correctly, so I think a lot of it is that. And the whole metering issue. The state and federal interactions probably help in that area.

CHAIRMAN WOOD: Andy, what percent of the generation participates in the ICAP market?

MR. OTT: Very high. I'll say 99.

(Slide.)

If I jump now to slide 36, I just wanted to go back and sort of reset, I had planned this to be the start of the break, but I do need to reset. I think if we go back and say, okay, what have we talked about. In all of the markets, whether it's ancillary, the day ahead market, the real time market, the concept of flexibility, flexibility meaning participation options, the market should support bilateral, should not discriminate against bilateral, you should be able to self schedule supply, if you want to schedule your resource to your load, and obviously there's the spot market access.

PJM again, the very deep spot market, the western hub has developed into a fairly liquid trading point. I think what that gives participants, and it's all players, whether it's small municipals to large LSEs or electric distribution companies or whatever, the point is they have a lot of different capabilities in this market. The reason you do and the reason you have it is fundamentally underneath everything you have consistency between the market and the operations. They complement each other. The price signals show what the operators want to happen. The system operators are happy if you make the commercial markets happy by putting trading hubs and other aggregations out there so that they can standardize products. Trading hubs are more than just aggregations of points. They're also points that are going to be less sensitive to local transmission congestion. They're sort of, since our western hub is 111 buses, if three or four buses in the western hub change price because of congestion, the hub price itself might go up by a penny. It's not going to be perturbed.

Markets hate surprises, so having that kind of trading point helps.

That goes back to the regulation and the spinning products. Again, markets hate surprises. If you can design the regulation and the spinning products to complement the real time market, the energy side, and not produce surprises like we have seen ancillary service surprises, and you don't want those. Again, you should avoid those, and if it does require you to try to step back and say, what am I trying to design, you know, an efficient energy market without surprises if you want. So then we go to if you're the municipality who wants to self-schedule your on-site generator to your load, buy spot if you need it, or sell spot if you have extra, that works here. All the way too you have a generator who just wants to be a merchant and sell energy and he doesn't want to worry about ICAP, all those are available to the participants, and the reason is again is back to fundamentals, the fundamentals of design allow you to get there.

The market information, I had said earlier to you that LMP is taking an idea, a way to operate the system, and making it available for everybody to see so really all it is is taking the security constrained economic dispatch that we used to do, making it auditable, repeatable, meaning you can track what the dispatcher decision is, and producing that information out to the world so they can react. That's really what it is. Obviously, if all that's consistent, you get the incentive. And then of course we talked about adaptation.

MR. O'NEILL: Andy, before you go on to the next one, you've mentioned generators and load serving entities. Could you just trace the history of marketer concerns and what you've done for them?

MR. OTT: If you'd ask that again?

MR. O'NEILL: The history of marketer concerns with the PJM market and how you've addressed them or accommodated them.

MR. OTT: I think one of the concerns I think in the beginning, when we very first brought LMP on was you're going to lose liquidity. For a few months, we did. There was a genuine concern. I can still remember the day we put nodal pricing in. It was April 1st. I was there at midnight. Five minutes after midnight, we were constrained, and the price that the 500 kV bus when negative, which is something people couldn't fathom. So there was an educational process. So for a little bit, we did have dip in liquidity in the western hub in the PJM contracts, but obviously that's come back tremendously. The western hub has come back as a very liquid trading point, so I think that the anxiety that was first experienced more or less sort of took care of itself because people got to realize by us posting information consistently and having the thing work, that helped. I think other areas though that are probably still being addressed are availability of transmission rights.

I think liquidity and availability of the transmission rights I think, you know, when you get into the concept of flowgates versus point-to-point FTRs, in PJM, you can buy a transmission right from the western hub to the eastern hub which is, if a lot of people were dealing western hub and eastern hub and they would have high volumes of trade between them, hopefully that market would develop into a liquid market. You could also define the flowgate which again the reason you would define such a thing is to get a standard end product for transmission, but I think that's still being solved.

I think there has been some increase in FTR availability. The day ahead market helped I think allowing people to lock in transmission ahead of time, so I think that concern -- let me refresh my memory -- what are the other concerns. Liquidity of FTRs, LMP --

MR. O'NEILL: Option rights.

MR. OTT: Again, we're looking at it. We're going to run, probably even May auction, we'll run it for real, then we'll run it again with options, and we'll show the market these are what they would look like, do you want them? If you want them, then of course we'll have to go back. We're just developing a way to do it to see what it would price out at. I think it's something worth doing, but my problem -- well, that's good.

MS. FERNANDEZ: Can I ask a follow-up question? In terms of flowgate versus market hubs, do you see those as alternatives or substitutes?

MR. OTT: I said this in RTO week, and I'll say it again. It's my story and I'm sticking to it. Flowgates and FTRs point-to-point transmission rights and flowgates which are path-based, you have path-based versus point-to-point based. They can co-exist depending on the definition of a flowgate. There's a lot of definitions out there.

Another thing I would throw out is, I think in some of the markets out there, and we can discuss this hopefully in detail tomorrow, a flowgate is not an equivalent product to an FTR because a flowgate essentially would only pay out, meaning be worth money, if that constraint, I mean the transmission line that was described by it was actually a problem. If a parallel line somewhere else in the system, you sort of have two ways to get there; this one's constrained, this one's not. A point-to-point right would pay money for that. You would have an economic value. A flowgate rate, depending on how it's defined, may not. In that case, it would be a substandard product, if you will.

If your goal in a flowgate is to create the same thing, like we did with hubs for the LMP, which was to create a commercial, a place where people would trade liquid, develop a standardized product. Then maybe defining a flowgate, you know, as a combination of FTRs along a path might be a better answer, but we can debate that as an industry, I think. But I think the simple point is they can co-exist as long as you define the flowgate correctly.

I was going to go back and talk about day-ahead markets starting on slide 37.

(Slide.)

I think it's important that you understand, and I think we talked about it a little bit, the day ahead market is much more than just a surrogate for the real time. It actually provides financial products. It was, when we put our day ahead market out, we allowed what we called virtual demand and virtual supply, which means essentially you're putting in a financial position. What that means is you could bid supply at the western hub. The western hub first off is a virtual point. It really doesn't exist. It's a mathematical aggregation but you can actually bid it as if it's a real supply point. You can also buy there. So it allows you to develop a very liquid, if you will, or very dynamic day ahead market.

I'll give you an example. In our day ahead market on a daily basis, the amount of virtual supply, virtual demand bids have been growing tremendously. You may have, on a given hour this time of year, like 32,000 megawatts of load bid. And you give an hour. The virtual demand bids will be something on the order of 20,000 megawatts. Obviously that's offset by virtual supply bids of something on that order, 19,000, 20,000 or whatever but the point is it's almost like trading twice. You have the real load that's bidding to protect itself, then you have all the virtuals that are really contracts, so you have this ability for people to react and to put in their contracts as they wish.

MR. MEAD: Andy, with regard to the virtual bids, is there a creditworthiness problem? Do you have many people defaulting on their bids?

MR. OTT: Actually we've had two defaults that have been well publicized, but I don't think that had anything to do with the virtual bidding.

(Laughter.)

MR. OTT: We track positions. In fact, obviously we're working just like everyone else, I'm assuming, to make that as close to real time as possible. We actually track in settlements a company's position. Again, if they go too far, we would require them to provide more credit, et cetera, so we have a standard. I don't think virtual bidding has aggravated the credit problem in that case. I think most of the virtual bidding is used essentially, again, it really goes back to flexibility. A customer has a forward contract. This customer wants to liquidate that contract against day ahead price. His counterparty wants to liquidate it against real time price. We have an impasse. They don't know what to do. The virtual supply/virtual demand concept allows them, the one guy can liquidate against day ahead and the other guy can liquidate against real time independently. They don't have to come to us and fight it out and decide what they want to do.

All this is really doing is allowing people to translate their position into the right market in PJM. I don't think it's changing necessarily the way they expose themselves to their market. But what it is allowing, though, is this dynamic, again, of the flexibility is allowing more trading dynamic, if you will. People are more willing to lock in forward.

One company will call me and say they won't let me lock in day ahead. I'm like, why do you care when you can do this? Once they understood it they're, oh. Then trading would happen where it wouldn't have happened before.

I think if you look at the next thing, obviously price sensitive demand.

(Slide.)

MR. OTT: Again, it's saying if the price is too high day ahead, I don't want to lock in forward. Obviously, that can be rolled into these demand response program. It's the same mechanism. So that kind, for this it's really a hedging tool. But if you wanted to convert that into something else, you certainly could. There would be no change in the software, because it's already doing that.

Then up to congestion bidding we have talked about. I think again that is probably a little underutilized in the markets. But I think as people understand that it really is an FTR hourly, if you will, for the real time market. In other words, you protect yourself on a daily basis with transmission rights that, you know, FTRs are financial rights that go against day ahead price. Then to protect yourself hourly in the real time market, you can do these up to congestion or just do a supply and demand lock.

Then you have FTRs and energy scheduling, which are again, financial. So all this stuff is around the physical spot that allows people to react to the physical spot. But remember, the consistency is always there between the prices and the physical market.

(Slide.)

MR. OTT: The next slide just shows you that we do actually put lots of data into our markets.

CHAIRMAN WOOD: Andy, was there much of a push for this to be done by someone other than PJM, in the private sector I suppose?

MR. OTT: There wasn't in PJM, and I think probably the reason was, everyone recognized that in order to do it where you can lock in both the transportation and the energy together, really the RTO needed to do that because of the fact that we were really the only ones who knew the transmission system.

So I don't think there was a lot of push in PJM to have that done. To be honest, I think a lot of people have been writing what I'll call contracts against our day ahead market. In other words, providing value added services, if you will. I have talked to a couple. I won't go into detail. But I've talked to a couple of companies about sort of indexing off that. So if you get that transportation lock in day ahead, there's a lot of flexibility that other companies can provide.

In PJM, it wasn't a big debate that we do this. I know it is in others, but I guess I would throw out that if you can get sort of the fundamental day ahead market with transportation included in there, I think the whole market benefits. But it doesn't really preclude other value added services, if you will.

Next slide. I want to skip to that slide.

(Slide.)

MR. OTT: Probably the only thing I would throw here is, again, to reiterate the forward market has all the physical modeling in there to ensure that not only is the market financially feasible, but it's also physically feasible, so that if you had to translate it, if all the load, the supply and the demand showed up tomorrow as it does in the day ahead market, you could reliably serve the system. That's the key.

So what I'm locking you into is feasible, meaning it could actually happen that way tomorrow. Now it never does because things happen. But the point is, it could. What that does is give you a certain consistency. That means that my day ahead financials, in other words, people are paying day ahead congestion and receiving for that essentially protection against the real time price. So it has to be a fundamental consistency between the two, or else I've oversold the system.

MR. MEAD: Andy, let me just follow up on that for a minute. Suppose you had a day ahead schedule, physically feasible and all that, and nothing changed in terms of supply and demand, but a line went down, a major line went down so that the day ahead schedule is no longer feasible, and some other things would have to happen, so in essence, you'd have more congestion. I presume PJM would be not revenue adequate?

MR. OTT: Yes. That would be true.

MR. MEAD: Where would the money come from? And is this much of a problem in practice?

MR. OTT: No. In practice, it's not much of a problem. Essentially, the money, if there was a shortfall that was -- in other words, you could get the money from other hours that were adequate. In other words, some hours have more money, some hours have less money, so you could get it from there. And again, it interacts with the FTR allocation, of course. But if you run out and you don't have enough money, it gets charged down to all day ahead demand. So it's just like uplifted just like any other shortage.

Really, we did have one month where it was a problem. I think it was the SMD month or something. It really got nuts.

MR. O'NEILL: If there was an outage, has there been any thought as to whether or not the entity owning the transmission line with the forced outage should have any financial consequences?

MR. OTT: Thought in whose mind?

MR. O'NEILL: As an incentive to keep the line up and in operation, if the line goes down.

MR. OTT: I think if you look at these markets and where they've gone, they've come a long way. I mean, you've got a lot of stuff happening here. These markets are very deep. They're working well. I think the part that hasn't got there yet is the incentive on the transmission side.

My personal opinion is, if you're going to give them upside -- or downside, excuse me -- you've got to give them an upside. And I think until we deal with that problem of how do you give them an upside without going over. But I agree with you. I think we need to deal with it, and that's probably next. But it's certainly a good way to incent.

MR. KELLY: Andy, on the previous slide, the reserve requirements model, that always means -- when you say "reserve" you always mean spinning?

MR. OTT: In this case I mean all the reserves. It's spinning, it's regulation, it's the other reserves, which are the 30-minute operating reserves. All of that's in there. In PJM it so happens the 30-minute operating reserve constraints are seldom binding, but they are in there.

If you look at the -- when we were designing our day ahead or our market, we have another couple fundamentals here. If you look at the fundamentals.

(Slide.)

MR. OTT: Obviously, we needed to develop day ahead financials that allows you to lock in energy and transportation. That was sort of key. That allowed the participants to lock in forward, get out of the risk of the spot.

But the other thing is, you can't be unrealistic when you do this, so they have to be coordinated with the actual reliability requirements of the system. So that was where we got the security constrained economic dispatch in the forward to match what -- and again, the same model is used day ahead as real time. That's very important. The consistency of those markets is critical.

The other thing, though, is you need incentive. You need incentive for resources and demand to submit the day ahead schedules. That was very fundamental. The next slide I'm going to explain to you that incentive.

You can design this badly. You can have a day ahead market, you can have a real time market and do all those things, and if you get one thing wrong, you blow that incentive, everything is gone, and I'll explain it to you in a minute.

And then of course you need the incentive to follow real time dispatch instruction. If a generator is locked in forward, he was already paid, what's his incentive to follow -- to deviate from that and follow the real time dispatch instruction that you need to preserve reliability? You have to have that there, too.

So while you're building these markets, we have to talk about incentive. PJM has no penalties. If a generator doesn't follow dispatch, he just doesn't set price. I don't go after him and charge him something. So obviously, if the market is working, there's got to be something there. So let's talk about it.

(Slide.)

MR. OTT: If you go to the next slide, the day ahead market at noon, we're determining the commitment profile that satisfies the demand bids, including virtuals, you know, the increment bids, the decrement bids, the actual demand, and the generation. And of course all the transmission models in there.

So everybody's locking in what they want day ahead. PJM clears the market. At four o'clock we post the price, and then we enter into something we call reliability assessment. Now we're in saying, okay, the market has just decided what it wanted. Now PJM has to decide are we comfortable. And there's two areas that we look at. One is reserves adequacy, meaning do we have enough generation that is committed and can start within the times we need it to be there to serve what we think is the peak load tomorrow?

But remember, we've already put the prices up. The LMPs already went out. So we actually display to the market that our load forecast and what was essentially locked in in aggregate in the day ahead market. So in other words, the market knows if we're scheduled short or long based on the day ahead, because we've put that information out to the market.

When we're developing the reliability assessment, it's very important. We actually schedule generation to minimize the cost to provide the product we need at that point, which was reserve. I'm not trying to go back and change the economics. The reason that is, is if a load, if load chronically underbids day ahead, and the day ahead will be low, if PJM comes in then and says, oh, I know better. I'm going to schedule economically during the reliability run to fix that and put the right number of generators on, then the real time price won't go up. So there's less incentive for that load to come in and put a realistic load in the day ahead.

So when we schedule based on minimizing the cost to provide reserve, then a generator with a high energy price and a low price to start, for instance, would be the one we'd pick. Then tomorrow, if we're scheduled short, the real time price would go very high. So all that load that came in, you know, maybe at 50 percent of what it should have, sees a very distinct price signal. So the next day their incentive is to correct that. If the RTO is in the middle fixing the problem, the incentive is destroyed.

Same thing with transmission security, but obviously there's less of that incentive there. We also do a transmission security assessment, and we say, do we have enough generation to fix the transmission problems we see for tomorrow that maybe the day ahead did or did not see?

Think about this. Say somebody bids a virtual bid to alleviate a transmission problem in the day ahead. It's great. It reduces the transmission congestion cost day ahead. All the load's happy. Because they actually lock into a lower congestion price than they would have. But now that increment bid that solved the generation problem disappears, because it's virtual. It's not there. So PJM would come in and see that that's not there and of course schedule generation to make sure that transmission was covered. But the poor guy who bid the virtual supply will now have to pay a lot in real time because the price skyrocketed.

And again, that's an incentive. The incentive if is he's short against -- if he locks into supply and the price went up, he's going to pay a lot of money.

(Slide.)

MR. OTT: So if you flip to the next slide, what we're saying here --

MR. O'NEILL: Andy, can I ask you a question? Is there a reason why you can't do all this simultaneously? That is to say, while you're running the day ahead unit commitment, you could put a constraint in against the real generators to see whether or not there's enough to serve load? Why do you do it after the fact?

MR. OTT: To give the -- we have a rebid period in between, and it gives the generators a chance to react. And again, it furthers the incentive. The point is, is I've locked in day ahead, then I produce --

MR. O'NEILL: So there's really a market in between the day ahead and the real time?

MR. OTT: Oh, yes. Yes.

MR. O'NEILL: And it's a real market because they get to bid into it?

MR. OTT: Right. And what I'm saying -- yes, exactly. Is that enough? And again, it helps heighten that incentive, and that's very important. It's absolutely critical that PJM, and this next slide says this.

(Slide.)

MR. KELLY: Andy, on your page 41 where you went from noon to four o'clock, you said that at four o'clock the market could be long or short. I thought I heard that.

MR. OTT: Yes. At four o'clock, we post what demand cleared. And that would be the sum of the actual demand, the virtual demand, less the increment, the virtual supply. And that's actually the real, quote, "load" that's being served by generation day ahead. And in any given hour, say that would be 25,000 megawatts in PJM for an hour. The actual load forecast that we posed could be 30,000, okay? So the market in total, okay, is locked in 5,000 less load than we think, we, PJM, have forecasted for tomorrow.

Our philosophy is that 5,000 shortage, we should show that to the market. The generators can rebid then. Load can go do its bilaterals to try to sell -- maybe they could sell scheduled generation into the real time to cover themselves. But the market will take care of that shortage.

PJM, of course, will also. We give them two hours to rebid. Then at six o'clock, we run that reliability run.

If people haven't self-scheduled in to fix the problem, some generators will take advantage. They'll say, okay, I'm going to lower my reserve price and skyrocket my energy price and see if they take me. But that's good. Because the loads know they'll do that, and then they have incentive to lock in forward, which is what you want.

But anyway.

MR. MEAD: Andy, sorry. The fact that PJM does do this extra commitment, it would seem to me tends to reduce the real time price relative to what it would be if PJM didn't do that. Because there's more cheaper supply available in real time than there would otherwise be. And it would seem to me the fact that PJM does this reduce the incentive for load to be in the day ahead -- to avoid the day ahead market.

MR. OTT: I strongly disagree with you, because I just said the opposite. The point is, is when we're scheduling in the reliability run, we're scheduling based on minimizing the cost to start a unit and operate it at minimum. We're not minimizing the production cost, which would be loading that unit economically. So we're actually giving deference, if you will, to units with low start and high energy price. So that would tend, if we did it that way, to actually increase marginal price tomorrow. Because instead of scheduling the economic generation, we're scheduling the economic stuff with respect to reserve.

So when that loads up -- in other words, if somebody else doesn't come and supply the energy, that 5,000 and that, quote, "reserve" loads up, the energy price skyrockets.

Now if your question was by having a rebid period and allowing the market to go fix itself, does that cause the price to go back down, the answer is absolutely. but that's the market. That's not me. See, the point is, is let's get -- I'm going to beg to get to this slide. It's very important that the participants decide what the degree of similarity between the two markets is, not PJM. PJM's role here is to facilitate the market and to make sure it's reliably scheduled.

MR. MEAD: So in this reliability readjustment -- I forgot what you called it.

MR. OTT: Reserve adequacy assessment?

MR. MEAD: You are committing more units that have low startup and high energy bids compared to the units that you would have to call on in real time.

MR. OTT: All right. Let me use an example. I'm 100 megawatts short, so I go and I have two choices. I have a unit with zero start and a bid of $200 to load up to 100 megawatts. And I have another unit that has a $200 startup and an energy bid of $30. If I were scheduling economically to minimize production costs for tomorrow, I would pick the second unit, the one with the startup and a fairly reasonable energy price. So tomorrow's energy price, if he were on the margin, would be 30.

But I'm not going to do that, because I'm procuring reserves right now. Because the market told me you already locked my energy in. So as far as I'm concerned, the market thought that we would have 100 megawatts less load, and they may be right. So I'm going to go after the zero startup cost unit. Because my cost of procuring reserves is zero. So I uplift zero. But if I'm right and they're wrong, tomorrow's price is $200. If they're right and I'm wrong, okay, then I've minimized the cost to provide the reserves I needed to reliably serve the system without costing -- so I'm minimizing the cost to the customer if I'm wrong. But I'm maximizing the cost if they're wrong, because that's their incentive to not be wrong.

MR. MEAD: If you had just committed a unit that has zero startup and $200 marginal energy, why isn't that unit also available in real time?

MR. OTT: It is. That $200.

MR. MEAD: Then why did you need that extra step to commit this zero startup unit earlier?

MR. OTT: Because I had to give the market a chance to react to the day ahead results. In other words, that generator may have originally had a startup of $1,000, but during the rebate period, he zeroed it out so I would pick him up.

MS. FERNANDEZ: Actually, a sort of a -- we need to break at 12:30.

MR. OTT: Okay. It's a wrap-up time?

MS. FERNANDEZ: Or sort of a warning you have about eight minutes left.

MR. OTT: That's fine. What do you want to hear about?

MS. FERNANDEZ: And a warning to the questioners too.

(Laughter.)

MR. OTT: Anyway, the point is, is when you're deciding on building a day ahead market, you have to decide who drives it. Are the participants' supply and demand decisions driving it and then reliability is done at a least cost manner to provide reliability, or is it the other way around? And in our case, we said we want to preserve that incentive for participants to what I would say realistically bid into the day ahead market.

Remember, there is no requirement for load to bid day ahead. So if PJM went in and fixed the market every time it was short in the reliability run, in the most economic manner, if we did that, then load would have absolutely no incentive to bid in forward.

And the point is, is if you want a forward market and you want it to be the market, then it needs to have the appropriate incentive, and that's why we designed it the way we did. The reason I highlight this, I think it's a difference between the way some of these markets have evolved, and we probably need to discuss it. And again, it may not be on the radar screen. It may be lower level than we need to be.

I probably should cover -- I think some people have asked me about timeframe, so I'm going to cover a few quick market timeframes, because I was asked to highlight those. I think if you look at the slide on page 44, I can't stress enough that the market's voluntary, meaning, involuntary means you can self-schedule or submit an offer. But I think the other things on this slide that I'd like to highlight, you have obviously the three-part bidding which I think has become more standard. The bids are locked at noon day before.

But the next bullet, Generation Offer curves in PJM are locked in for the entire 24 hour period. We do not allow hourly bidding. That is fundamentally different than others.

Now by the same token, underneath that, we allow changes in self-scheduling decisions or transactions every 20 minutes, or, you know, with 20-minute notice. So what we're really saying there is if you as a customer need to react to our price, meaning you want to change your mix, you want to schedule a transaction or take one off or self-schedule a generator or turn it back to us for dispatch, you can do that with only 20-minute notice. You can react very quickly to what the real time price is saying.

But you can't react to that by changing your price bid. Our problem with changing bids every hour is that some of these markets have been very predictable, meaning that, in our case, if you bid very high, you've got to live with it for the whole day. In another case, if you can bid hourly, you could bid high just during the very top periods of the day and then bid low the rest. So there is more opportunity to push the price.

And I know, Joe, the market monitoring crowd has pointed to this feature as very fundamental to our market working without being able to manipulate, if you will.

I think the other issue, though, is if you're going to lock in the price for a 24-hour basis, you must allow the flexibility for near term changes in quantity so that gives the hydros and some of these other units the ability to react to changing conditions on a near term basis. So if you're going to, as we did, with the lock of price, so you can't manipulate price, then you have t be able to react to price by changing your quantity. I think it's very fundamental to what we've done. So if you did one without the other, it would be an issue.

Probably now I just, considering five minutes, why don't I just give in and ask for questions.

(Laughter.)

MR. OTT: Is there anything I didn't answer for you? I think I'm here for the next two days.

MR. O'NEILL: If we ever do get to Nirvana and demand responsive bidding, do you think we'll be able to bypass the second pass in the day ahead market? That is to say, that when the bids actually mean what they say they mean?

MR. OTT: The second pass is doing -- I think reserves adequacy can certainly be bypassed if you had that. And let me be honest. There are times when in the normal course of operation when it's time to do the reliability run, we look at the day ahead market sufficiently scheduled, we say, don't need to do anything. So there are times today that when the market is sufficiently scheduled day ahead, we don't do anything in the reliability run. But we have to go check.

So I think always having that check. No whether or not that check results in a movement I think will lessen when you have demand, because you'll use that as your reserve.

MR. O'NEILL: Because, as I understand it, PJM estimates what demand is based on some historical econometric estimate based on weather and things like that.

MR. OTT: All kinds of things.

MR. O'NEILL: And if you have responsive demand, the demand not showing up may be in anticipation of high prices, and so consequently, your second guessing them may not be hopefully at some point in time, the requirement to second guess will go away.

MR. OTT: If that response to price is there, I agree with that. And I think you'll always need transmission security assessment. And again, it's sort of a catchall to cover to make sure that if the market didn't take care of the reliability problem, we're going to step in and do it. But, again, we have to step in and do it under the rules. If we step in and do it outside the rules, we screw up the incentive, and that's the important thing. YOu have protocols.

In other words, a knock on these RTOs is they can run wild and take over and it's a black box. And I think the point is if you have certain protocols, the way we handle things, and it's designed such that it doesn't contradict the market, I think you're there. Otherwise, it is actually susceptible to these problems.

MR. KELLY: In your opening remarks, you said one of the key features of PJM was its adaptability. We're now considering doing a rulemaking that would lock in certain market design features. Presumably, we could change them with another rulemaking. But I guess -- do you have any advice for us on what level of detail at which to do a rulemaking so that we're not constantly -- you know, with great detail, we constantly redo a rule to allow adaptability, or if we don't do that and we have a lot of detail in our rulemaking, we may inhibit adaptability.

MR. OTT: I'll quote my colleague. I think he was fairly eloquent where I probably couldn't be. He told you, go as far as you think you can and then go further. I agree. I think probably the level of detail probably needs to recognize regional differences, but I think beyond what I would say is measured regional differences, you need to standardize.

I know my anxiety, I go watch my customers schedule energy and see what they go through, just to get a contract through, and it's just because of lack of standardization in both the user interfaces and some of the market rules. And I think from their point of view, you need to at least get to that level.

But there are some regional differences between us that you'd probably have to recognize. But I think there can certainly be standardized interfaces, standardized rules, standardized ways of dealing with the seams.

A lot of what we discussed today I think is about the level the detail it would be at. But again --

CHAIRMAN WOOD: In that statement, regional differences, what is a region?

(Laughter.)

MR. OTT: Again, I think the regional differences I was thinking about, to be honest, were some of these reserve areas, you know, the MAC area of NERC and ECAR versus NPCC may have different just different ways of dealing with reserves. And again, like I said before, PJM nonspinning reserves really has not been an issue. I think you can standardize to say you have spinning and regulation, but you may leave optional that one. That kind of regional difference is where I was at. So yes, I agree.

CHAIRMAN WOOD: Just thought I'd ask.

MS. FERNANDEZ: Well, with that, thank you very much.

MR. OTT: Thank you. From my perspective, it was great.

MS. FERNANDEZ: We're going to take a break now and come back at 1:30.

(Whereupon, at 12:30 p.m. on Tuesday, January 22, 2002, the Electricity Market Design and Structure Conference recessed, to reconvene at 1:30 p.m. the same day.)

A F T E R N O O N S E S S I O N

(1:40 p.m.)

MS. FERNANDEZ: Could people start going to their seats so we could get started?

(Pause.)

MS. FERNANDEZ: Our next speaker is Charles King, Vice President of Market Services for the New York ISO, who is going to discuss the market design in the New York ISO, and highlight the differences between what we had in our morning presentation. And with that, I'll turn it over to Mr. King.

MR. KING: Thank you very much. I really appreciate the opportunity to speak here today and highlight some of the market design features that the New York ISO utilizes and perhaps some of the things that we're going to be moving. I'd also like to thank Andy for doing such a great job this morning describing a lot of the basic features that are common to all of the systems in the Northeast, the LMP pricing data, the real time markets, et cetera, and I think you'll see, as I go through the presentation, there's a lot of similarities but there are some differences, some subtle, some not so subtle, that really reflect choices that were made to address different operating issues and system issues that we face.

(Slide.)

The presentation today, I was asked to cover these areas. What I did is put together a set of slides that is fairly comprehensive. I don't expect to get through all of these slides today, and what I'm going to do is focus on just those that describe some of the differences. But you have a complete package there that you can take away with you to kind of fill in the gaps at your leisure.

The drivers in the market design, first we had the type pools, the power systems. In setting up a market, our design philosophy was that we wanted to do several things. One is we want to maximize the use of the transmission system and in New York, we've seen that New York is highly constrained and maximizing the use of a highly constrained system was a paramount issue in the design. We also wanted to rely as much as possible on market incentives, incentives for market participants to follow the instructions of the ISO. And this became more important as we went through the design phase. I began to get involved with this in the mid-nineties and kind of followed it through to the actual implementation of the ISO in December of '99. Through that time, we saw the structural changes within the New York companies change from a vision of being vertically integrated utilities to one where the generation was divested resulting from the settlement process with the state public service commission.

So our market design had to reflect those needs. You'll see that as we progress.

(Slide.)

Maximizing the use of the transmission system is a very important theme. It's both important with regard to the ability to move power within New York State, and also between New York and its neighbors. You see here that New York lies between the Canadian provinces, New England, and PJM. It's centrally located. Their needs at different times of the year to move power in different directions. In the winter, we're often selling power at North when the Canadian provinces are peaking, and in the summer generally we're importing. When the systems in New York, PJM, and New England are peaking, the system that we put in place, we believe, allows us to maximize the use of the system in a variety of conditions. And I have some examples that we won't have time to get into today, but they're included in the supplemental material that's with your handout.

(Slide.)

I talked a little bit about the restructuring. Let me just revisit that. In New York, the settlement process was a bit different than in other areas. The process evolved through a settlement arrangement with the public service commission as opposed to a legislative process. The end result is that the majority of the generation in New York has been divested and is owned by merchant companies and not owned or affiliated with the incumbent or load-serving entities in New York. That's a fundamental difference.

That occurred just prior to the launching of the ISO markets in December of '99. It does set up different incentives. Clearly a merchant-owned plant, when you talk about locational pricing, they're very interested in seeing if their unit is on the margin, they want their bid to set price, and they want to be paid the clearing price for the energy that they sell to the market. You could contrast that in a vertically integrated regime. There may not be as much emphasis on the generators, the price that the generator sets. There may be more emphasis on the ability to sell schedule, for example, and using the generation as a physical hedge to hedge the price paid by load. So there are some different incentives that relate to the industry structure that have to be accounted for in the market design, and I think it's something that as each area goes through this process has to be cognizant of these differences.

(Slide.)

We have a shared governance structure in New York, an independent board of directors, a self-sustaining board of directors, and a set of stakeholder committees which we work together to develop and approve the market rules in New York and make enhancements where we deem necessary.

(Slide.)

What I'd like to do is actually talk a little bit about the unique system characteristics in New York. We've talked about congestion, we've talked about thermal limitations, voltage limitations in New York. We have those that we need to deal with but in addition, our system is also limited by stability, which is the ability of old machines to remain in synchronism. We have limitations that relate to disturbances that can occur in the central part of the state that can literally cause the system to shake itself apart in under ten seconds. So it's another type of a constraint that is prevalent in New York that you may see to a more or less degree in other areas of the country, but it's one that is very difficult to manage operationally, and that what you want to do is you want to maximize the use of the transmission system, yet protect against these kinds of disturbances. That has presented a challenge to us. It's something that over the years has driven us to implement more automated processes to ensure that we do protect against these types of contingencies.

We implemented security constrained dispatch in the early eighties and it was these types of problems that motivated us to do that. The presence of these problems motivated us to keep this type of structure in place going forward. As we developed the ISO, in fact that technology became the cornerstone of our real time market. So it's these limitations and the degree of congestion that we see in New York that have certainly shaped some of the design decisions that we've had to make as we developed the markets. That combined with the divestiture of generation I think you'll see how that plays out in some of the differences that I'm going to show you on the following slides.

(Slide.)

I just threw up a transmission map to give you a sense of some of the problems that we operate with day in and day out. Sixty-five percent of our load is located in the greater New York City Long Island area. Generally what you're trying to do with this system is move power from the west and from the north to offset higher costs, resources in the southeastern part of the state. That was the way the power pool operated for many, many years. In layering a market on top of this, we needed to again set up sufficient incentives to both encourage generation to be built in the constrained areas. Ultimately, you'd like to be able to build out of the constrained areas but also have the proper incentives that will allow the operators to continue to operate the system and encourage the market participants to follow those instructions.

And now with the divestiture, the incentives are a bit different with the divested generators than with the prior vertically integrated utilities.

(Slide.)

In terms of the actual overview, you'll see that the components in the New York market are very similar to what was discussed this morning. We have bid-based markets for energy regulation, we have bid based markets for spinning and non-spinning reserves, and because of the contingencies that I spoke about, the stability issues, much more importance is placed on knowing how much reserves we have and precisely where those reserves are. That's very key. That's an element of our design process and that's what I think has driven us to having explicit availability bids for reserves and solving that simultaneously with the energy market. Those reserves represent real constraints that we have to operate to and we feel very strongly that the market should reflect all constraints, not just the formal constraints. We have the three-part bid, the self-scheduling, although it's done through a bid-based mechanism, the ability to self-schedule is part of the market, installed capacity, again we're involved with the regional discussions with PJM and ISO New England to develop a regional set of consistent ICAP rules. We have already adopted the unforced capacity concept that PJM had been using. We have deployed that, and recently I believe the market rules that we're using have been adopted actually by New England.

So what we see happening, particularly in the area of ICAP, is that the rules are moving closer to a consistent regional set, and I think the process that's been put in place will drive us there fairly quickly.

Transmission congestion contracts. We have those. The settlement system, we have two settlement systems, day ahead market and real time, and I'm going to get into these in a little more detail.

(Slide.)

Locational pricing. I do want to mention that often our system is confused. People think we have a zonal pricing system and we don't. Our pricing system is designed to be a full nodal pricing system. The generators are paid based on the prices at their specific locations in the system. However, due to metering, the lack of billing quality metering, we are not able to see the load in real time, exactly where it is, so we actually combine and develop a weighted load price that load pays. That's done on a zonal basis. But in terms of the actual mathematics, behind the model that we use, it is a full nodal pricing system. Once we make some infrastructural changes, we would be able to implement a nodal pricing system very easily.

MR. MEAD: Could I just follow up on that with regard to the demand side? You said you didn't have meters that could identify in real time what the load was at particular nodes. Ultimately are the demand bills based on sort of an aggregate actual load, or is there some sort of load profile?

MR. KING: I believe load profiles are used. You can work around the problem of not having the real time metering by using load profiles and estimates, and then truing up with your hourly metering after the fact. It's just a more laborious process.

MS. FERNANDEZ: In terms of your using the two different methods for the load and for the generator, is any of this socialized, or does the load capture all of the cost?

MR. KING: To some degree, really where it plays out is in the billing processes because what we have to do is go back, and after you obtain the meter readings from the utilities, we can then back cast and calculate what load was actually consumed at what price. It ends up being a lengthy process. I don't think it introduces any substantial errors or any socialization. It really just affects the billing process and how long it takes you to get to the point of having a final bill.

MR. O'NEILL: If we went to demand responsiveness, would this be a problem, given that the demand is usually at a node, and if they can't see the price at a node, is that a problem with getting more demand response into the system?

MR. KING: I think that clearly having better technology deployed would certainly promote more demand response. We actually had a fair amount this past summer. I've seen numbers 400 or 500 megawatts in some of the programs that we've set up. As long as you can go back and verify that you got what you paid for, I think it works. Again, it kind of works out in the billing process that you have to go back and gather the data, do the analysis to determine that yes, you actually got the relief that you paid for.

MR. O'NEILL: But that's buying people off the system. There's another system that says I see the price and I decide not to consume.

MR. KING: That's the part that I think is lacking in that down to your average customer, retail customer, if they can't see the price, they're not going to be able to respond. It's more than just seeing the price. Actually, they can see the price. The thing is are the mechanisms in place for them to take advantage of it and act on it. That's where I think more work can be done.

(Slide.)

Moving on to slide 10, I agree with Andy's comments on flexibility. We designed our system to allow bilateral transactions, address existing transmission agreements. This was a very challenging area. How to deal with preexisting transmission agreements going forward. Scheduling of energy limited resources, resources that can only operate at certain levels for certain times of day. How do you best use those resources. Dealing with municipal customers, power marketers, all these diverse interests, and it certainly is a challenge to design the market rules to accommodate all of these diverse interests. And we believe that the rules we have put in place do address these needs

(Slide.)

I have kind of a walk through on the next slide that illustrates how it's sort of a day in the life of the New York market, how you kind of walk through from the day ahead market which closes at 5:00 a.m. We run a security constrained unit commitment which essentially develops our secure operating plan for the next day, and again because of the high degree of constraints and the types of constraints that we have to deal with, we're very cautious about making sure that we have secured the resources, both energy and ancillary services, reserves in the right location to make sure that we can operate the system on the following day. This was something, there was actually quite a debate during the design process because conventional unit commitment theory says you commit over a week because you have diverse resources and in order to come up with an optimal solution, you need to commit for a period of week.

When you start talking about layering markets on top of power systems, a number of people believe that well the market should decide a lot of these decisions, so we had to arrive at a balance and really it came down to being one day. We absolutely have to be sure we can operate the system tomorrow, and therefore that drove the 24-hour unit commitment process. So that plan that we come up with does that, it awards both energy and ancillary service contracts, and then we move into the end day process. This is a difference in that we use an hourly process to make some of the adjustments looking at the security of the system. End day load forecasts, which are more accurate than those that you'd have available the day before, and allowing parties to schedule additional bilateral transactions.

We allow parties to change bids to reflect circumstances that may exist today that were not foreseen the day before, but functionally that hourly scheduling process that's on that slide essentially does the same thing that I guess the second auction that Andy talked about does the night before. So the hourly process allows for variations in schedules additional bilateral transactions, changes in bids, and that moves us into the real time market where we use a security constraint dispatch which will make some tradeoffs as it sees opportunities to move ancillary services between different resources to save money, it'll make some of those tradeoffs as we go into real time. It then produces a base point, a megawatt level for each of the generators. We've always used that kind of an approach, providing signals to the generators, again, because of the need to manage these very difficult constraints that we're faced with.

(Slide.)

Now what I'm going to do is skip around a little bit. I've given you background information on each of the major market areas. What I'd like to do is just jump ahead a little bit and focus on some of the unique characteristics on slide 16, some of the characteristics for the day ahead market. The constrained unit commitment software has a day ahead objective. One of the differences is that we have a pass that we use to make up any shortfall that we feel we need to do to secure the system for the next day if not enough generation was committed and we think that we'll be short on reserves, or that we will have some operating problem. We will make additional commitments. We actually include the effect of those changes in the day ahead price. That is perhaps a more subtle difference in the process between New York's implementation of the security constraint commitment and the standard market model. We also incorporate some mitigation activities in the security constrained unit commitment. I'm going to get into that in a little bit more detail further on.

As I said before, the ancillary services are secured and priced day ahead. All the reserves, the ten minute non-sink and 30-minute reserved are all secured and priced a day ahead, again, part of that secure operating plan. We have, there's a number of options available to load. First of all, load is not required to bid into the day ahead market. There's no explicit requirement. However, there are a number of mechanisms that load can use. First of all, load can bid in and say, well, I want to purchase X amount regardless of the price, I want to hedge. They also have the ability to bid what we call price cap load bids. This is the amount that a load is willing to buy if the price is no more than X. So they can tell you how much they buy day ahead based on price using those mechanisms. In addition, recently we introduced the virtual supply and demand abilities similar to what Andy spoke about this morning. And so those hedging tools are available as well.

MR. MEAD: A question about the price cap load bid.l Is the price that's in that bid the zonal price for that particular load based on the load profile that you talked about a minute ago?

MR. KING: We have eleven zones, and if I were bidding a price cap load bid in Zone G, it would be compared against the price that we calculate in Zone G which is a weighted average of all the generator bus prices in that zone. That's how those prices are calculated.

MR. MEAD: If you don't know in real time what the load is actually consuming, how do you know whether the customer has adhered to its bid?

MR. KING: In the day ahead market, it's really a financial instrument because really what you're asking is how much do I want to lock in day ahead. There's some that I want to lock in no matter what the price is, so they'll tell us that through their schedule. The part that they are willing to lock in up to some price, that is handled through the price cap load bids.

MS. FERNANDEZ: Actually there's two questions I wanted to ask. I think there are some differences between the New York ISO and PJM. You commit additional units the day ahead, and you put those into the prices. I'd like to sort of get an explanation as to why you think that's a better way of doing it than PJM.

The other is, in the day ahead market, you can have different bids per hour as opposed to one bid for the entire 24 hours and again as to why you think that's a good idea.

MR. KING: With regard to the first question, one of the things that is very important, the fact that we are doing a 24-hour commitment process is that we want to sort of with this theme of encouraging the generators to follow the instructions of the ISO, we want to send the incentives that if you tell us your unit's going to be there tomorrow, either to provide energy or reserves, we want to be sure of that commitment, so by locking into the prices day ahead, we're paying the generators day ahead to provide energy and we're paying to provide reserves. The expectation is that those resources will be available to us in real time to operate the system. So it accentuates the price signal, it accentuates the incentives to perform. I think that's the reason for including the additional commitment in the calculation of the prices.

With regard to the second question, allowing bids to vary hourly, we think that adds a lot of flexibility to the system and gives the operators more options. And also allows it takes some of the uncertainty out of the real time bidding for the generators. In other words, if they have to try to speculate the day before what I think conditions are going to be like, I'll probably include some additional amount for uncertainty, whereas if I can go in in real time and actually look at the load, what it is right now, and reassess the situation, I've taken some of the uncertainty out of it. And during times when conditions are competitive, that should drive your real time prices down because I've taken out some of that uncertainty. So I think the hourly process helps facilitate that.

MR. O'NEILL: Chuck, does it give you more of an opportunity to exercise market power?

MR. KING: I think that the opportunity to exercise market power is really more a function of the structural conditions in the system. If you have a system where all players can bid in and have a chance of getting taken, then you won't have the opportunity to exercise market power. If I have a situation where a portion of the system becomes bottled or isolated, then regardless of whether I'm talking about the day ahead market, or the real time market, once the opportunity is there, market power could be exercised whether it's intentional or not. So we have to guard against all of those opportunities. But I'm going to spend some time a little later in the presentation talking about what I call a mitigation framework that we're thinking about that I think addresses all these needs using a common structure.

Yes. Market power can occur in real time. It can occur a day ahead, and we have to be vigilant. I think market power, market monitoring is a very important feature of the market while we're going through this transition.

As long as you have barriers to entry in terms of can new generation locate wherever it wants whenever it wants, we're not quite there yet. And load does not necessarily have the ability to say no if it doesn't like the price. As long as you're in that transition, you're going to need things, like a very vigilant market monitoring program, an ICAP and other such things to allow the market to be competitive under all circumstances.

Let's move to page 19.

(Slide.)

MR. KING: This discusses some of the differences with the real time market. The basic chassis is again very similar: A security constraint dispatch algorithm. Again, we take it another simultaneously co-optimize energy and reliability services for the different reliability markets, and we will make tradeoffs in real time if it's economic to do so from a production cost point of view.

The actual pricing, we use sort of an ex ante pricing based on the schedule's generator base points. Every five minutes we're looking ahead, forecasting what demand will be and where we need the generators to move and the pricing is based on the schedule. That's just the ex post pricing mechanism that Andy spoke of this morning.

Quite frankly, the ex post pricing method is one that I think is a good idea. That's something that I think that we are looking at as we look to the next generation of this kind of software, but both accomplish the same thing. The ex ante method, we do impose a penalty structure in that if you overgenerate, you're not paid, if you undergenerate, the way it was originally implemented, you would buy the difference at the real time price to make up the difference.

We have recently introduced some market rule changes in working with our committees to allow more flexibility here where generators do have the ability to follow the price to some extent, such that it allows that additional flexibility but still leaves us with a system that encourages the generators to follow our instructions.

Again, if we have two much of generators not following the base points that we calculate, we can run into reliability problems, and in order to address that, we would have to reduce or actually increase the operating margins on our critical interfaces, which would kind of defeat the purpose of opening the transmission system.

You open a transmission system, you want to use it. We don't want to have to artificially restrain the transmission system to accommodate some of these other practices. So we've had to take measured, cautious steps in moving towards some of these self-scheduling activities in the real time market.

Is there a question?

MR. MEAD: Yes. I'm trying to understand the ex ante pricing concept that you just talked about. Let's imagine our day ahead schedule has been established and all that and we're in real time and you develop some constraints so that you need some additional generation east of the central constraint.

Okay. So you need some extra generation in the east and you think if people follow their bids, you need to raise the price to, I don't know, $80 or something or other. Can you discuss in a little bit more detail what his ex ante pricing -- does this mean that you'll set the price at $80 even before the generator responds to your instruction?

MR. KING: The price is set as if the generator had exactly followed the operator's instructions. And then there's a balancing to that. If the generator actually overgenerated, it would not be paid for the amount of the overgeneration. If it undergenerated in billing, it would be buying the difference at the real time price to make up that which it failed to generate.

We've relaxed that again with some market rule changes that we made last year where we allow some degree of flexibility in allowing generators to follow price as long as it's economic within their bid curves that they've provided us. So really what you're doing is, with the ex ante pricing, you're basing the price on the schedule. We asked you to generate at a level of 100 megawatts. We based the real time price calculation on that, and then settle up against it.

The other approach is to look at where the generator actually wound up, and essentially what PJM does is, they use a little OPF program, a very clever little program that says, all right, once you filter out for one reason or another which generators you don't want to contribute to setting the price, and they have a criteria for doing that, say all right. Well, these generators are just so far off they're not in the market as far as setting a price is concerned.

Then when you get down to the set that's left, you look at where they wound up and you say, well, since these generators are here, the price must have been X, and you sort of back into the price that way. That's the other way to do it.

MR. MEAD: So in New York, then, if you think you need \$80 generation in the east, you set the price at \$80, and if that generator doesn't in fact produce, then you charge that generator \$80 and ask some other generator to produce it instead then?

MR. KING: Well, what we would have done, first of all, we don't set a megawatt signal -- or a dollar signal. We would not say, you know, the price is $80, go chase it. We actually calculate a megawatt value and we actually say we want this generator at 100 megawatts in the next five minutes. The expectation is, the generator will increase its output to that amount. Then in billing after the fact, it would get paid consistent with that schedule and how it performed relative to that schedule.

On to page 20. Actually, I'd like to back up to 19 again. Not a major difference, but the ranges we allow for bids are different. Obviously, we have the $1,000 bid cap, offered cap, but the minimum in New York is minus $1,000, and we're at zero in PJM. Normally this doesn't cause a problem, but we have run into situations at times of the year when there is excess energy on the system, that you can see negative price spikes in New York due to transactions being curtailed in the other area, because without having the comparable bid ranges, the choices are made differently.

In New York, with the bid range down to minus $1,000, the market will decide which transaction should disappear as the price drops. Whereas if you don't allow that, then, those choices will have to be made through some other mechanism, and you can see that reflected from one area to the next. We've seen it a couple of times show up as negative price spikes. It doesn't happen often enough that it's an issue, but the reason I did bring it up is does show how rules set differences between areas can reflect themselves in the pricing -- in the neighboring areas. So that's just an example of that.

On page 20, this is the subject of how you actually set the locational price and determine which units are on the margin and which ones are not. And this is an area -- it's a level of detail that we're not really going to have time to go into today. I just wanted to mention that it is something that you can see a fair amount of variation. And I think it's important to just recognize that there are differences. This is a topic that we could spend hours talking about what the rationale is for why you choose one method over another. I've just highlighted a couple of things here.

Again, you know, where one area uses a price signal and generators follow a signal, we're using, in the case of inflexible units, units that aren't able to follow a dispatch signal, we have a hybrid pricing method that we use that allows the LMP to reflect those costs when that inflexible unit is actually needed, and then when it's no longer needed, the price will be set by other units.

And the fact that we're very dependent upon these types of units, it's important for us to have those price signals in our market.

I digress for a minute. In terms of the history of how the New York system developed, there have been a number of instances where, under the old vertically integrated regime, tradeoffs were made to, rather than build transmission in certain areas, we relied on quick start generation.

In areas such as New York City that are very constrained and very hard to build new transmission lines, the appropriate business decision to make at different times may have been, well, if we put quick start gas turbines in a certain area, we can operate our system at higher levels and not have to actually add new transmission. And so that's the history of how the system was developed. We even actually have limits on facilities on different cables, transmission facilities, and they're actually allowed to operate at higher levels because of the presence of the quick start resources to relieve any overload should they occur.

This is important, and again, it emphasizes why we have placed so much emphasis on knowing where those reserves are and being able to utilize them when we need them because of the fact that even some of these limits are based on the fact that those are present. And if we were to not have that, we would probably have to revisit and probably lower some of those transmission limits. So, again, it emphasizes the high degree of congestion that we deal with.

Move on to slide 24 and 25. In terms of transmission reservation and scheduling, we have a somewhat different approach in New York. We do not use an explicit reservation process. And when we look at how the whole -- you kind of have to step back and look at the whole process for utilizing the transmission system and the fact that we utilize a central dispatch process to maximize the use of the transmission system, we felt during the design stage that a physical reservation system would be prone to hoarding, and we wanted to make sure that the transmission system was available to those that valued it the most. And so we utilized a bid-based approach.

And through essentially when you do that, the notion of the various classes of transmission service, firm and nonfirm, simplify to whether you're willing to pay the congestion to use the system or not. And so that's a little bit of a difference. In the traditional transmission reservation process, you first reserve the transmission, like reserving your seat at the theatre, and then at some later time you go, and when you choose, you go to sit in it.

We sort of do that all at once.

When you schedule a transaction through the New York site, you're simultaneously reserving and scheduling a transaction to use the system, and that maximizes the availability of the transmission system for all to sue it.

Now because we do a 24-hour commitment process, one of the areas that we work with our market participants to try to improve is they'd like to have a little bit longer term certainty in terms of being able to schedule long-term transactions. So we're in the process right now of developing what I've called a prescheduling process. And we deliberately use different language here not to confuse it with the traditional reservation scheduling approach.

In prescheduling, we will allow prescheduling of firm transmission out to 18 months. And when you do that, you will be simultaneously reserving and scheduling a transaction, so there's no separate reservation process followed by a scheduling action. They will occur simultaneously.

In addition with that work, we're also looking at ramping limitations and developing a system to allow market participants to manage ramping constraints between the control areas which represent the amount of change that you can make to an inter-area schedule on any given hour. So those are two improvements that we're making.

But we think that the financial scheduling process offers a lot of advantages, and this prescheduling will tie in directly with that. One of the things that it allows you to do is set up counterflow transactions. And counterflow transactions are transactions that can basically sit there at the border. And if we find that we have limitations in day that would cause us to want to curtail day ahead transactions, what the counterflow transactions allow us to do is to preserve the day ahead transactions, not curtail them, but instead accept transactions that flow in the opposite direction that relieve our limitation yet allow business to continue.

And this actually mimics perhaps in a more centrally dispatched way what NERC has been attempting to do with its market redispatch pilot. The idea behind the NERC market redispatch pilot was that in your NERC TAG, if you know you're going to be scheduling a transaction across a limited flowgate, give us a counterflow transaction that if the congestion occurs, we'll schedule the counterflow transaction, relieve the constraint, and essentially allow you to avoid a TLR.

And the use of the counterflow here in New York with the financial evaluation of transactions on an hourly basis essentially accomplishes the same thing. It avoids the need to curtail day ahead transactions. Yes?

COMMISSIONER BREATHITT: You said one system has more potential for hoarding? What was that that you said?

MR. KING: Well, if you have a physical transmission reservation system, if you don't have appropriate rules around that to release the transmission, somebody can come in and essentially pay the reservation fee and reserve the right to use the transmission but never actually use it. And so the question is, well, how does it become available to others?

That automatically falls out of our system. But you can see systems where this will be a problem.

COMMISSIONER BREATHITT: But then there needs to be, if you have that kind of system, then it would need to have the right incentives for reselling. And that's what we used to call it in the telecom world, are the resellers.

MR. KING: Absolutely.

COMMISSIONER BREATHITT: Could you have that system and have incentives, the right incentives to resell?

MR. KING: If you're asking can you create a physical reservation system that has the, you know, rules to encourage reselling, probably.

COMMISSIONER BREATHITT: Or incentives that would make that more attractive.

MR. KING: I believe that can be done. But I think you have to make sure that that really happens. We've had some problems on some of the seams issues that related to hoarding issues. And you do have to take the time to deal with those. Otherwise, you'll find that the transmission system will be underutilized.

As an extension to this, we're looking in the operations area of -- you know, the mindset typically is, is once we get to the point where we can't redispatch the system any further to relieve a constraint, we then have to look at curtailing transactions in order to free up that room. And we're also looking at ways in which we can, well, instead of curtailing a transaction, what if we added one on the other side of the interface? Do something that's a little bit more market facing rather than always cutting because that was the way we always did it.

In terms of a constraint like our Central East constraint, where we might find in the past we relieved the situation where we had no more generation to move to adjust, we would cut a transaction coming from the West, perhaps we could gain that same ability by adding a transaction from the East. So we're looking at ways of doing that to try to have a more market facing approach to dealing with the congestion across the control area boundaries.

We're also looking at reinstating transactions more rapidly as well. So these are some areas that are under development between the operation staffs of the ISOs.

COMMISSIONER MASSEY: When you say we would add a transaction, who would add a transaction?

MR. KING: The control area operator. For example, if we needed to relieve a Central East constraint by 100 megawatts, I might have to cut a 200 megawatt transaction from the West in order to realize that relief. If the conditions are such, though, that I could add a 150 megawatt transaction from New England, add a transaction and effect the same relief, that would be a more market facing approach of addressing the congestion rather than disrupting the transaction from the West that had already been scheduled.

COMMISSIONER MASSEY: You're saying a transaction that's in the queue some way for some reason, but that was rejected earlier because of the constraints on the system?

MR. KING: It may have been rejected because of economics or constraints. But, yes, it would be something that would already be in the queue that we could simply reinstate.

(Pause.)

I'll also mention on this slide that we're working on an open scheduling system, which will allow for one-stop shopping for market participants to schedule a transaction, but it also allows for movement of operations data between control areas to facilitate the transaction checkout process that occurs every hour, and this is often the place where some transactions fail is that not all the information gets around appropriately.

So this is work that's ongoing and actually has generated quite a bit of interest across the industry.

(Slide.)

MR. KING: On slide 25, these are some additional characteristics. The blended flow-based export transmission service charge. That's where we do something a little bit different, and rather than having a single export rate, we actually have one that is -- when I say "blended", it's a function of the different rates for the different transmission owners in New York. Again, the other areas I think use a flat rate.

It's something that we're looking at and that as you move to larger markets, I think the issue goes away. Because in theory, you wouldn't have these export taxes. And I think that's probably the direction that you need to move in.

But the key to moving in that direction is that you have to assure the revenue recovery, you know, that's part of the revenue recovery mechanism for the transmission owner. So if you're going to remove these charges as you go to create larger markets, there has to be assurance that the transmission revenue requirement can be recovered through other means. So there's a larger discussion that has to occur there to help that along.

The two other bullets on this slide refer to the topic of generation interconnection criteria, and I won't dwell on them too long, but I do want to mention that in New York we use an access based methodology as opposed to a deliverability methodology in that we only require that a new generation owner be able to connect to the system.

In theory, you can get into -- this is a little bit different than traditional generation planning under the old vertically integrated regime where you would be looking to site these things optimally and making sure that you can utilize the full up of the plant. Here the paradigm is different with a market. I as a generation developer may be willing to build in a pocket knowing that all of the generation in the pocket won't be able to be used at the same time. But as a generation developer, I may be willing to do that, because I may feel that I'm competitive. I'm going to be able to bid at a rate that my generation will be used and somebody else's will not.

And so we've kind of taken that approach with our access based process. We allow that. We don't have a deliverability requirement that means that all of the generation has to be able to -- you have to secure transmission service between the generation and the load.

We will simply connect you up, and it's a business decision.

MR. HEGERLE: Does that equate to a PJM energy resource as opposed to a capacity resource?

MR. KING: I'm not sure precisely what it equates to in PJM. Maybe that's something we can explore in a little more detail tomorrow.

Special protection schemes. We also, we fully address those. I'll give you an example of what a special protection scheme is. We may have a situation where under certain fault conditions we'll have an unstable result. Remember I talked about the ability of the system to shake itself apart in ten seconds? You can set up protective relay schemes which will essentially disconnect large blocks of generation if certain fault conditions occur.

And the question that you have to ask yourself is, do I allow those schemes to be part of the normal system or not? And we do have special protection schemes already in existence in New York where generation will be rejected in certain areas if certain fault conditions occur. And we do allow them going forward as long as they have been fully studied. So that's something that is an additional flexibility that we have with respect to those.

All right. Let's move on to slide 29.

(Slide.)

MR. KING: We had quite a bit of discussion on this this morning. We have financial hedging instruments. And in the LMP market, you really have two kinds of hedging going on. One, you have hedging that does not involve the RTO or the ISO. That's the contracts or differences type of arrangements that people make where they lock in a price at a particular location. And in order to hedge the congestion costs which represent price differentials between locations, we have our transmission congestion contracts. That's the financial hedge that we offer.

We auction these and they cover periods of up to five years. Sixty percent of the transmission capability I guess, if you will, is auctioned through our central auction process that we run. And the TCCs that are awarded, they're on a basis they're fully funded, which means that regardless of what happens to the transmission system, the holder of the TCC will always be paid in full.

So in the short term, in the heat of a deal when you're setting up transactions, you have the certainty to know that I will be paid dollar for dollar on those TCCs and I can use those as part of how I structure my transaction. So that is a difference.

And the other part of the difference here is that the TCCs, the funding for the TCCs is balanced with the transmission owners. So any shortfalls that occur because the transmission system did not perform as well as we thought it was going to do in the case that we used in the auction, that shortfall will be funded by the transmission owners, and then they would collect it through -- their transmission service charges from the load in their areas. Any overcollection -- and that can occur -- any overcollection in transmission rent is refunded to the transmission owners. So everything balances against the revenue requirement that the transmission owner has.

The way the money flows is that the auctions occur. We award the contracts. We collect the money, and the money is given to the transmission owners, and that reduces the amount of revenue requirement that they have to recover from their native load. So that's how the whole thing kind of knits together.

MR. O'NEILL: How often do you do the settlement process?

MR. KING: I know we run a number of different auctions. And I believe at the closing of each of the auctions, that we don't hang onto the money. So it would pass to the transmission owners. So we do the auctions for the longer term TCCs. Then there are monthly reconfiguration auctions that occur. So I think anytime there is an auction, you can assume that the money is moving the way I described.

MS. FERNANDEZ: In terms of the transmission owners, is their rate design in terms of the wholesale customers is set up so that they are able to flow this straight through? There aren't any retail rate caps or whatever that would sort of end up having the transmission owners, actually, I'm seeing is there an immediate issue there?

MR. KING: I don't know the answer to that. In each case, that may vary.

MR. MEAD: Can I ask, when there's a revenue shortfall, how do you determine which transmission owners make up the difference?

MR. KING: There was an agreed upon formulation that was a megawatt mile-based approach. That is documented in I believe the ISO/TO Agreement.

On thing this kind of opens the door to, and this is just some idle thoughts with regard to ITCs, but if you're looking for incentives and having the funding mechanism set up this way, offers the possibility of providing some incentives. If you had an independent RTO auction, for example, these rights, the case that is set up, the load flow case is very important and the assumptions that go into it because that sort of determines your base level. You can visualize a situation where you have an ITC working with an RTO. There could be incentives set up that if the ITC can improve the performance of the system against that baseline that the revenue over collection portion of that could provide the incentive to do things like schedule maintenance on the weekends and do the types of things to improve the availability of the transmission system so that you're sort of working against that baseline. Having that occur that way, you've got kind of a nice checks-and-balances there between the not-for-profit RTO and the for-profit ITC, so there's certainly some potential there that is probably worth exploring.

MS. FERNANDEZ: Could I ask you another question on financial rights? How liquid is the market for those? I mean is there much of a resale market?

MR. KING: I'm not aware to what degree there is a secondary market. I believe there is, I just don't have a good sense for how much that's utilized.

Moving on to ancillary services. We covered this already to a degree.

(Slide.)

The high degree of congestion in New York, and the challenges that we face with the various types of limits that we have to deal with drove us to a design where we fully unbundled all the ancillary services and have explicit availability bids which allow us to do the full simultaneous co-optimization which provides the energy and ancillary services at the least cost and gives us the ability to address the locational requirements because it's not only important that we have the reserve but we have to have the right amounts in the right locations, and we have to be able to assure us that we have that locked up day ahead, and then can adjust at end-day. The day ahead market and the real time market mechanisms and the hourly scheduling process that we use all kind of work together to assure that that happens.

I have an example that's in the supplementary slides that are at the end of this package, and I'm not going to have time to go through them today, but they show that during the peak week, the first week of August last year, that this ability was very important to us because it allowed us to do something that we haven't been able to do before, even as a power pool. What it allowed us to do is when we got into the very tight operating conditions that week, and during that week on three successive days we set new peaks, yet during that time we were able to continue exporting power to neighboring areas of some degree. We did have to reduce it, and we were able to make those adjustments through the hourly process and the fact that we knew precisely where those reserves were. So we were able to continue to exporting, we were exporting to Ontario, PJM and New England, all through that week at various times. To me, that's a real measure of efficiency because if I didn't have the certainty with regard to where those resources were, I would have had to have operated it more conservatively, and I would have had to have called back those exports. So I think when we get into these very tight operating conditions, you can really see the benefit of some of these practices.

COMMISSIONER MASSEY: I have a question. Are you suggesting then that those types of additional bells and whistles would be a good idea for a standard market design that was applicable everywhere?

MR. KING: I think I would say it a little bit differently. I think that a standard market design should not preclude the ability of an area to utilize those processes. As Andy mentioned this morning, if the nature of your system is that it's not important where the reserves are, just that you have them, then maybe you don't need to go to those extra procedures, but in areas where it is critical where we have made, through the evolution of the system, have traded off generation for transmission, okay, these things are important and we need the ability to manage them. So I think the rulemaking is critical so that it allows the areas that need to do it to do it, and the areas that maybe don't need to do it, they would transition into it.

One thing you find is when you go, when you develop electricity markets, the system behaves differently than it did before you had markets. You see different flow patterns and you find that congestion starts to appear where you never had congestion before. I think that as markets evolve the areas, they need to ascertain and determine when it's appropriate to add in these additional, as you say, whistles and bells. I think it will become evident when they're needed and you put them in. We've already determined in New York that we need to have these features and have included them in our design.

Other areas may evolve to that over time as you more fully utilize the transmission systems in the various areas. I think I've covered everything on ancillary services unless there's other questions.

MR. MEAD: Let me just ask one question then if I could. Once a generator has been selected to provide ancillary services, let's say in the day ahead market, and we come to real time, actually I have to questions. First of all, is the energy from that generator that's providing ancillary services put into the same bid stack with other generators that are offering to provide energy in real time, and secondly to the extent that a generator that has been put on reserve and paid to be put on reserve, if that generator's asked to produce energy, what does it get paid?

Does it give up its capacity payment when it starts producing energy, or not?

MR. KING: No. We wanted to send the incentives to be sure that the resources were there when we need them, so if we award an ancillary service contract day ahead, that's a done deal. Even if end day through SCD through security constrained dispatch, change our mind and find that, no, it would actually be cheaper to take the energy from this unit and carry the reserve somewhere else, they're still paid a day ahead, so that provides an additional encouragement. It's also a signal to them that, you know, we do expect, if we need to we're going to utilize your reserves. So whatever is paid day ahead is a done deal. When you get into real time, if we do the tradeoffs for energy and reserves, if we back a different unit down to provide reserves, they will be paid a lost opportunity cost, and they'll also get paid for the reserves. One thing that we're looking at is, the question is raised, should we also pay a lost opportunity cost on the day ahead if we hold a unit back to provide reserves a day ahead. That's an open question that our committees are looking at.

One of the things it does, from the point of view of something that's bidding a generator, you can actually go in and bid your entire generator, say it's a 500 megawatt unit, you can bid 500 megawatts energy, you can bid 400 megawatts of reserves in the various categories, and it adds up to more than the capability of the generator. But the software will figure out what the optimum mix is so you don't have to spend a lot of time trying to optimize your bid because the program will do that.

MR. MEAD: Is the energy from an ancillary service generator put into the same bid stack?

MR. KING: Yes.

MR. MEAD: And it's dispatched purely on its energy bid?

MR. KING: When you do the simultaneous co-optimization of energy in the ancillary services it's looking at the energy bid and the availability bids for the various ancillary services, so it solves all that simultaneously so it takes it into account. It takes all of those into account. The benefit of that of course is you get least cost dispatch for meeting all those constraints, your system constraints and your ancillary service constraints.

(Slide.)

On page 36, long-term capacity markets, again ICAP is a very important feature of the market, and as Andy indicated this morning, we also have a requirement that installed capacity providers bid into the day ahead market, and that's very crucial because that's what gives the system operator first crack at the resources. So we have the obligation on the load to contract with the resources, and then the resources are obligated to make themselves available to the system operator. So that all works the same way. Where the differences are is really in some of how we do the qualification tests. Unforced capacity, that's really a measure of what you're getting. If you have a generator that's nominally 100 megawatts through the year, the unforced capacity concept really takes into account the fact that it has outages and may not, on average, operate at 100 megawatts. So the UCAP principle is more of a measurement and we think it makes good sense. In fact, that's a change that we've made from our original design. We have a monthly certification process and the deficiency penalties that the load may be subject to or applied on a monthly basis, and the monthly basis is really something to try and address the changes that occur, retail access.

As I indicated earlier, the ISOs in the Northeast, New England, PJM, the IMO, and the New York ISO are all working together on developing a common set of ICAP rules. We have agreed on a common set of principles on what an ICAP market should provide. Now we're working on the next stage. Given those common principles we agreed to, what are the common market rules we need to implement those principles.

(Slide.)

Next, I'd like to get into the area of market mitigation. In this particular module, I'm going to go through all of the mitigation slides. I don't think we spent very much time on that this morning, so I think it's an area we can kind of fill in a little bit.

The area of monitoring and mitigation is very necessary in this transition period that we're in because we can't just have generation appear wherever it's needed. There's still some barriers there. Load is not free to just say, no, I don't like the price, I'm not going to consume today; we're not there yet. We have some good pilot programs in the demand area, but we still have a ways to go, so we do need things like ICAP to assure reliability and market monitoring and mitigation to assure competitive markets. Really what the goal is of a good market monitoring plan, you want to be able to have competitive supply/demand relationship over the full range of your system under all conditions. As I said, there can be times. You know, we tend to think of our power systems as an all-lines-in system. That's what it looks like.

But day to day that configuration can change drastically depending upon forced outages, maintenance conditions, other phenomena. The sunspot activity that we talked about this morning, those affect New York as well.

So all those things you need to be able to address and they can create conditions that allow market power to exist. The question is how do you address that and assure that you have a competitive market while not interfering unduly in the market itself. We've adopted, in New York, the concept of a conduct and impact standard. We look at the bidding behavior of all the market participants. We look at bids that have been accepted during competitive periods and when we see changes in behavior that can constitute the conduct. The question is, once conduct has been observed -- if an entity has raised its bid, for example -- does that have a material impact on the market. So it's a two-stage test that this process is based on.

I look at this as kind of a framework in that you have this structure and you can kind of parameterize things like thresholds, margins, reference prices. And those can change depending upon the time frame that you need to monitor the market. In other words, the parameters that you would use in a real time environment would be different than the ones that you would use in a day ahead market. There are things people are taking into account day ahead, risk premiums, for example, things like that, that once you're in real time, that's not an issue anymore and you don't have to address it then. But again the parameters all work together the same way. The discussion really comes down to what must the parameters be set at for these different mitigation needs.

(Slide.)

Moving on to slide 38, just briefly, the market monitoring staff is accountable to the NYISO Board of Directors. In addition, we have an independent market advisor who reports directly to the board who provides oversight. We are in the process right now of responding to the two FERC Orders to develop a comprehensive mitigation approach, to address a number of the mitigation activities that we're engaging in right now. Some of these listed below are what we refer to as in-city. That was a mitigation process that was set in place as part of the divestiture of the Con Ed generation. Prior to the ISO mitigation plan coming into effect, we had the real time in-city mitigation and statewide automated day ahead market mitigation referred to as the famous AMP. But when you look at these and what we're going to be proposing, you'll see that all these have the same functions. Bases on the conduct, impact types of tests, and the use of parameters, thresholds, margins, and reference prices to effect the mitigation.

(Slide.)

Moving on to 39, I would just list here the different things that our market monitoring department looks at. Physical withholding, economic withholding, uneconomic production, and so on, right down to installed capacity and issues of collateral. All of these things are fair game and we look at all of them.

COMMISSIONER MASSEY: Are you going to discuss each of those, or you're just summarizing them here.

MR. KING: I'm summarizing them right now. I'll be happy to answer any specific questions.

COMMISSIONER MASSEY: Do you know how you define "economic withholding" on your system?

MR. KING: Actually, if we have installed capacity providers, we track that very carefully. We look at all of the installed capacity providers and in terms of, you were asking with regard to economic withholding? Again, we apply the conduct test because over the course of the market, generators have bids accepted during competitive periods. That allows us to develop what we call a reference price. If we see a generator --

COMMISSIONER MASSEY: Is that generator-specific reference price?

MR. KING: That would be a generator-specific reference price. That's not calculated in a vacuum. We solicit data from the generators, and our market monitoring plan gives us the authority to acquire that data. We use that data and we also consult with the owners to arrive at these prices. But what they do is allow you to establish a baseline that represents bidding in a competitive market, and when you enter into an economic withholding scenario, you'll see a change in conduct. Somebody will suddenly increase the bid and that will avoid the generator from being picked. What that may do, if that has an impact that will cause the price to rise in an area which may benefit the other generators in that company's portfolio. That's the mechanics. But really we monitor it by establishing these reference prices and then monitoring conduct relative to those reference prices.

COMMISSIONER MASSEY: Is this done like in real time, the monitoring?

MR. KING: Yes.

COMMISSIONER MASSEY: How quickly could you figure this out?

MR. KING: We actually have a fairly large mitigation department and we have our system set up so that they will be alarmed when certain behavior occurs, and we can investigate fairly immediately what is happening. We also use something I call watch list technology. Really what that is is many times you'll see the changing conduct well before it actually has an impact. You'll see that perhaps a generator was bidding $40 and all of a sudden is billing $500. We don't wait for the load conditions to occur that would cause that generator to be accepted. When we see that change in conduct, we immediately start having discussions and trying to determine, well, is there a rationale for that and maybe there is. There may be times when there is a rational reason why a bid would be increased above the conduct thresholds. But once we determine that there is an issue here, we have watch lists set up so that we can list specific generators in this watch list and the mitigation will occur automatically for the units that are on that watch list. In other words, most of the time you can see it coming I guess has been our experience.

MR. O'NEILL: Chuck, can I just get a clarification. You said reference price. Would that be the equivalent of reference bid?

MR. KING: Yes.

MR. O'NEILL: It's not the price yet, it's what they bid.

MR. KING: It's really an offer. To be technically correct, I should say reference offer.

MR. O'NEILL: That's fine.

(Slide.)

MR. KING: Moving on to slide 40, just to summarize some of the benefits of the approach, is that you can parameterize the mitigation to address the specific needs that you have, whether they be real time, day ahead, yet use the same framework. The reference offers should reflect historically accepted competitive bids whenever possible. We have a consultation process that we always follow to ensure that we understand why certain bidding behavior is taking place. The automated procedures that we've developed using these same structures allow us to prevent that loss day, or you've accepted a very high bid, and then have had a tremendous impact on the market, but because of the timing you can't do anything about it until the next day. Through the automated procedures, we can capture that next day. And I think the last bullet is important. By parameterizing these quantities, and committing to review periodically, or as the system changes, it sends an incentive for market participants to kind of build out of a congestive pocket. They know that yes, we have set certain parameters for today but as more generator gets added to a pocket, we're going to review them, and we'll change that going forward as the market in a particular area gets more competitive. So it's important I think to have an incentive that you can ultimately build your way out of a pocket.

(Slide.)

Slide 41, I tried to contrast the mitigation process in New York with that in PJM. The differences there really go back to the market rate authority is a little different for the generators in PJM. My understanding is that they weren't granted market-based authority when congestion is present in the system. So the exception is that when there are voltage constraints on the three major interfaces in PJM, the West, Central and East, those are exempt but for normal thermal types of limits, congestion, the process of cost capping is used where PJM essentially reduces the bids to a level of cost plus ten percent. In other words, you can think of it in terms of the framework that I was talking about, the reference offers in PJM would be cost plus ten percent, or in New York, we're looking at the competitive bid history, unaccepted bids during competitive periods to determine that reference price. It's not necessarily cost-based so it allows more flexibility.

MR. MEAD: Did I hear you say that this cap applies when thermal constraints kick in, but not voltage constraints?

MR. KING: My understanding of the exemption is that it applies only to voltage limits on the west, central and east interfaces in PJM. Historically, PJM voltage was the more limiting constraint in their system whereas stability limitations were the dominant factor for many years in New York. Voltage limitations, the ability to maintain the proper system voltage profile in a bulk power system was a critical area for them. So again it kind of goes back to the underlying problems that exist in these systems and how that affects how the markets develop.

MR. MEAD: My understanding was that the caps kicked in when there were transmission constraints that limited competition from the outside. If my understanding is correct with regard to the rationale, I'm not sure I understand why it matters whether voltage or thermal constraints or stability constraints are the limiting factor.

MR. KING: I think it's really how the market monitoring plan is written. My understanding of the way it's implemented, and perhaps we can have more discussion on it tomorrow, but if a generator in PJM has more than a five percent impact on relieving a constraint, then it's eligible for cost capping. PJM has two sets of curbs for each generator. They have the actual engineering cost curbs, then they also have the offered curbs that were submitted for the generator. They can float back and forth between those using this cost capping process so it's a little different process but again I can relate it to the framework that we're talking about. The cost plus ten percent is a surrogate for the reference prices or offers that we use in the New York Plan.

(Slide.)

MR. KING: The last slide, slide 42, again just illustrates this framework. If you have a black-and-white copy, it will be hard to read. But again, we focus on the conduct impact test as the foundation of the mitigation process, and the n through the choice of triggers, thresholds, margins, consultation, that's how we enable the mitigation when it's needed.

And the goal, again, is to only utilize the mitigation when it's needed to restore competitive markets. It's not something that you want to be mitigating when you have a true scarcity condition. You only want to be mitigating during noncompetitive times, and so we think this structure is an excellent way to strike that balance.

That concludes the slides that I had planned to talk about this afternoon.

MS. FERNANDEZ: I think we have a few minutes. We need to take a break fairly soon. But were there any last questions?

MR. KELLY: I have a question. Are the market participants under an obligation to consult, when you consult with them, could the say I don't want to talk to you? Is there something about their conditions of getting on the grid that require them to participate in consultations?

MR. KING: With regard to a mitigation scenario or the establishment of reference prices?

MR. KELLY: Both.

MR. KING: We have means to establish the reference prices. Generally we have found that the generation owners are more than willing to talk to us about that, because we'll establish prices, and we have three ways of doing it. I talked about the accepted bids during competitive periods. We can also negotiate prices, and that's during this consultation process.

You know, we would discover needs in terms of various factors that go above and beyond just simply fuel costs. So that would be an example of consultation. However, I guess if the entity refused to consult, we can calculate reference prices using what I call a default price, where we look at the costs for similar units elsewhere in the system and develop sort of an average cost.

So we have a way to do it, whether the party wishes to discuss it with us or not. But we've generally found that people are very cooperative and like to talk to us about it.

MR. KELLY: It's in their interest to consult.

MR. KING: It certainly is, yes.

MR. KELLY: Thank you.

MS. FERNANDEZ: If there are no other questions, thank you very much. Let's get back together by say 3:20. If I say 3:20, we'll get started no later than 3:25.

(Recess.)

MS. FERNANDEZ: Could people start getting back to their seats so we can get started? Can we get started? That's always a threat. You sort of do the first slide, and then people will sit down.

(Slide.)

MR. LaPLANTE: Good afternoon. I'm going to focus my discussion on ISO New England's selection of standard market design and describe the differences between our implementation of the standard market design and what's in PJM today.

The excellent job that Andy did and that Chuck did relieved me of the responsibility of describing some of the more intricate details of what's going on. But I'll be happy to answer any more detailed questions as well.

Before getting into standard market design, I'd like to describe where we are in New England today in terms of markets. In May of '99, New England went live with market-based rates in seven different markets. It was a single settlement system with no congestion management. There were in fact seven markets: Energy, ICAP, operating capacity, ten-minute nonspin, 30-minute operating reserve, ten-minute spin and AGC.

For a while we were down to five markets. The OPCAP market went away, and the ICAP market wasn't functioning. At this point we have now six markets functioning. At the time the markets were put in, we anticipated they would be interim. They've been in place In think longer than anyone had anticipated.

(Slide.)

MR. LaPLANTE: What is SMD or standard market design? We didn't mean to be presumptuous with this slide and describe a vision for the nation. When we made the decision to adopt PJM's current market design, we called it standard market design and the term seems to have caught on.

Standard market design in New England is PJM's current design with a list of enhancements. I'll describe those enhancements more in later slides, but they're really driven by two things. There may be physical differences between PJM and New England that caused us to do something, or there may be sort of policy or long-standing regional practices that have caused us to be different than PJM. So when I get into the enhancements, I'll talk about that in more detail.

(Slide.)

MR. LaPLANTE: Why did we go to SMD in New England? In early 2001, we had a schedule for a custom CMS/MSS design that showed going live in the first quarter of 2003 with just CMS, or locational marginal pricing, and a full multi-settlement and congestion management implementation not until 2004.

This was a new, unproven market design. Our experience with the initial market made us extremely leery of putting in another untried market. The final budget was higher than people had expected and than we were comfortable with.

There also was a growing concern in New England that standard offers would be expiring, retail standard offers would be expiring at the end of 2003, and there was concern that the wholesale markets in place couldn't support a full retail market, so we had a target of 2003 at a minimum to get a new set of markets in.

(Slide.)

MR. LaPLANTE: With that as a backdrop, the decision to switch to SMD became fairly easy. After looking into and working with PJM, we found that we could implement locational marginal pricing and multi-settlement about a year earlier and at lower cost than the original design that we had been contemplating, the New England design.

And along with that, because SMD has been prove in PJM and with many of its features working in New York, it's a proven market design with much less risk of problems upon implementation, one of the factors driving the long lead time of the New England design was the number of software modifications, software design and development that had to take place to support a new design. By going with an existing product, we significantly reduced the time for development and the risks of implementation related to software.

These are big, large software projects. So anything that reduces time or risks for software has a beneficial impact on schedule and cost. This standard market design was also a step towards convergence of the Northeast markets. When we made this decision back in March, we knew RTOs were on the way. We knew things were going, but we didn't realize the speed at which things were moving. And standardizing markets has benefits in market design and software development as well that should improve design and lower software development costs in the long haul.

(Slide.)

MR. LaPLANTE: A few of the features I'd like to highlight is that market participation in the standard market design is voluntary. It provides the ability for participants with physical supply to self-supply requirements and for self-schedule resources to opt out of the market. This is true in the energy market and the ancillary service markets. Participants that have physical resources can either self-schedule or self-supply in the market. This is the flexibility that Andy and Chuck have alluded to, and it's essential for the participants to feel comfortable with the market.

One of the points that hasn't been made yet today is that in New England now, the spot market accounts for only abut 25 percent of the energy. Seventy-five percent is traded bilaterally. I think the numbers in PJM and New York may be a little different, but the vast majority of energy in all three Northeast energy markets trades bilaterally and not on the spot markets. I think that's an important fact to keep in mind as you analyze these markets. I don't know what the split will be as we move forward between the day ahead spot market and the real time spot market, but I think most transactions will continue to be done bilaterally.

(Slide.)

MR. LaPLANTE: Some of the major enhancements to the current PJM market that SMD and New England will have. Andy mentioned that PJM is going to a spinning reserve market. We'll be implementing that spinning reserve market just about the same time that they do, sometime late this year or early next year.

A spinning reserve market is needed in New England because we rely on thermal units to provide most of our spinning reserve, thermal and hydro. And those units often have to be backed down in real time to provide the spinning reserve. We need a market in place that assures that those units will receive their lost opportunity cost. If they're not receiving their lost opportunity cost, then they might not be willing to follow the dispatch instructions. So a spinning reserve market is an important feature for a wholesale market in New England.

MR. KELLY: Mr. LaPlante, at least in my vocabulary spinning reserve market and operating reserve market are not the same thing. Is that the same in your vocabulary?

MR. LaPLANTE: Yes. Spinning reserve is just spinning, and operating would be offline units as well. It could be ten-minute offline units and/or 30-minute offline.

MR. KELLY: So you won't have an operating reserve market, you will have a spinning reserve market?

MR. LaPLANTE: Correct.

MR. KELLY: Thank you.

MR. LaPLANTE: New England does have two other operating reserve markets today. Those will not be continuing on their standard market design. That's something -- it's an unfortunate disconnect. We hope to fix it after standard market design.

ISO New England controls all generation in New England, which is a physical difference from both PJM and

New York. PJM is sending dispatch signals out to control centers which then send signals to individual generators. We have an electronic dispatch system in place that sends signals every five minutes. So the pricing algorithm we have will be calculating dispatch points directly for all generators in New England.

Actually, that's a tool that we developed jointly with PJM, their unit dispatch system that they're using to improve their dispatch and doing congestion as well. Historically, New England has always used penalty factors in dispatch. We have units up in Maine that have heavy losses, one that dispatched to several regional loads. So to dispatch the system economically, we've always included the penalty factors.

For this reason, we need to include the losses in the prices or we could have an inconsistency between the prices and the dispatch. A unit up in Maine might look cheap, but when it's actually brought to the load, it becomes much more expensive. So if we didn't include the losses, the units that were offline would feel that they should have been dispatched.

So in order to get an economic and efficient dispatch, we need to include losses in the prices and penalty factors in the dispatch.

When we put our markets in the first time, we had a fairly broad market mitigation authority. And early in the year 2000, the Commission ordered that we get more specific in how we mitigate and the standards for market monitoring and mitigation. We adopted standards similar to New York standards for monitoring and mitigation. We will be working with New York in the coming months on developing new standards that we'll use in implementing SMD.

We anticipate something like the automated market mitigation procedures that Chuck described. The key mitigation will be taking place in the day ahead market. Before day ahead prices are complete and the day ahead market is finalized, the conduct and impact screens will have been applied. Because we won't have hourly bid changes, there really isn't as much of a need for real time market mitigation.

(Slide.)

MR. LaPLANTE: One of the enhancements I'd like to talk about in a little more detail is the treatment of hydro generation in the day ahead market or hydro generation in the standard market design. For a number of regions in PJM, most of the hydro is self-scheduled, so they haven't had to come up with market mechanisms for scheduling and operating hydro.

We in our current market design spent a good two-and-a-half years struggling through this issue. We had a number of problems with it when we first went live, and I think we've learned enough to take a good design into standard market design.

There are really two ways for a hydro unit to participate in the day ahead market. The first is, in keeping with the philosophy of flexibility, would be to self-schedule all their generation as a possibility.

Another possibility would be to self-schedule a portion of generation and offer prices for any additional water.

So there may be a base level that has to be generated to maintain river flows or river levels, but it would be consistent with a pumping schedule. That could be self-scheduled. There may be extra generation which could be more flexible, which could be dispatched economically or depending on the ISO, the owner has the opportunity just to schedule it all based on price. The results of that dispatch produce financially binding hourly schedules as part of the day ahead market. If we get a number of megawatt hours fit in by a generator, we will optimize those prices over the day ahead market, and a financially binding hourly schedule comes out.

(Slide.)

You can see that on the chart on this page, the dark colored area would be the day ahead schedule, the financially binding day ahead schedule. There is capacity available above that. There's unlikely to be sufficient energy to run the unit at full output for that whole time. The treatment of that available energy in real time is difficult and there have to be a number of options given to both the owner and the system operator to make sure that the owner can meet its economic objectives, but the system operator knows how much capacity is available in real time.

(Slide.)

So there are three options that we'll have in the real time market for hydro generation in SMD. The first would be the fixed day ahead schedule where we'll send out basically dispatch signals to the generator that exactly conform to the day ahead schedule. Under SMD, the generator has the ability at all times to either lower or raise the output. So depending on market conditions, the operator may decide to increase or decrease the output during the day.

A second way is we would send out dispatched signals with a fixed day ahead schedule but dispatch below that so that the ISO would honor the megawatt hours committed day ahead, but if the energy became economic, based on the bid prices we received, we wouldn't generate, so we would save that energy until the time when it was economic.

Then finally the third option would be full economic dispatch based upon offer prices. This would generally be done without participation in the day ahead market and we would just treat a hydro generator as a thermo generator in real time, and generate based on the prices we have, and it would be up to the owner to self-schedule the unit off if we ran out of energy. This structure I think gives hydro generators a pretty good opportunity to participate in the market.

MS. FERNANDEZ: Could I just sort of clarify? Would these be three options that would be available to the hydropower operator?

MR. LaPLANTE: These could be selected individually every day. An operator can pick any one of these on any given day.

MR. KELLY: Mr. LaPlante, could you run through option B one more time for me?

MR. LaPLANTE: The real time?

MR. KELLY: Yes.

MR. LaPLANTE: The day ahead schedule would have generated an hourly set of megawatt output values. Also submitted is a bid curb or an offer curb for the generation associated with that. If in the peak hour, we were expecting an output of 100 megawatts and the price was $40, if the generator had bid $50 for that section, for that 100 megawatt level, we would drop down the output to the $40 output level in real time.

(Slide.)

One of the things we learned in our initial set, in New England's initial market implementation that we need to understand exactly how all the business processes have to be done internally, the market rules to find the market for the market participants, we've spent a lot of time developing a set of internal business processes for a market operator to run a market for SMD. Once we've completed those, that's something in helping advance the standard market design, we'd make those available to whoever would be implementing a standard market design at no cost.

(Slide.)

This is an area, a controversial area, financial transmission rights auctions. It was controversial in New England and it really caused delay of New England coming together on a CMS/MSS decision by probably three to six months. It was a very difficult process for the market participants to agree on who should get either the transmission rights or the money from the rights. Andy actually did a pretty good job of describing our process in New England. All financial transmission rights will be auctioned off. The revenue from those auctions will be allocated to -- I have load here -- more correct, it's congestion-paying entities. Those are really transmission customers.

The NEPOOL tariff says that transmission customers are the ones that will pay congestion, so they're the ones that will get the revenue from those auctions. This assures that those who value these rights will get them.

(Slide.)

MR. MEAD: Let me just stop you for a second. The allocation of this revenue. Is it fair to say it's in proportion to payments for embedded costs?

MR. LaPLANTE: No, it's in proportion to load.

MR. MEAD: What's the rationale for allocating on that basis?

MR. LaPLANTE: Load pays network service essentially so in a way you're right because we're in the same position as PJM in terms of network service; 99.99 percent of all customers take network service. That's paid on a dollar per kilowatt of load. So the allocation of the rights is based on load also.

MR. MEAD: I see. Thanks.

MR. LaPLANTE: One of the unique features of the New England market is that there are many small public power entities that participate directly in the market. I have ten megawatts to 100 megawatt years. There's actually seven that are under ten megawatts. That's been dealt with in New England through the use of a couple of joint action agencies. The Massachusetts Municipal Wholesale Electric Company and Energy New England support these participants in the wholesale market. I don't think it is practical for a small utility to participate individually in the markets but the joint action agencies seem to have been able to allow them to participate in the market directly.

In the discussions and the allocations of the financial transmission rights, there was a lot of negotiation with these utilities to make sure that the existing contracts they had, which were hard won battles back in the 1970s, would be carried forward, especially since a number of these entities were in Boston, which is congested. The generation was outside of Boston, and they put special arrangements to make sure that they would get the FTRs or the financial transmission rights necessary to support their load. In this arrangement, we haven't gotten to implementing the final design of this yet, so we're hoping that all the theory on the allocation works out and that people get what they expected to when we finally allocate the auction rights and the revenues.

MS. FERNANDEZ: I just wanted to clarify, in terms of the existing contracts, they would be changed over to pure financial rights?

MR. LaPLANTE: The existing contracts are for generation, and the generation say might be from Boston to a generator out in western Massachusetts. The key was to get enough financial transmission rights to get that generation inside the congested area.

MS. FERNANDEZ: So they would be financially indifferent?

MR. LaPLANTE: Exactly. They want the revenue from the FTRs that they would need to get their generation to their load.

MS. FERNANDEZ: Okay.

MS. SHEPHERD: Can you talk a little bit more about how the joint action agencies are formed and specifically how they're funded?

MR. LaPLANTE: Actually I happen to work at one of them, so I can. One is Massachusetts Municipal Wholesale Electric Company. They are a creature of the State of Massachusetts. They were formed in the late 1970s, early 80s, to allow Massachusetts utilities to issue tax exempt bonds to fund power plants. They made a number of unfortunate investments in some nuclear plants but it's been tough. They've also functioned as a technical agency or consultant to the municipal as well.

And I'm not as familiar with the Energy New England in Connecticut, but I think that's a spinoff of the Connecticut Municipal Electric Energy Cooperative which is, I think, a creature of the State of Connecticut.

MS. FERNANDEZ: Let me ask a follow-up question to Jennifer's. In terms of very small customers, would there be any barriers or reasons to sort of prevent them from acting together? I believe the ones you talked about, you were saying they were creatures of the State. If the entities themselves wanted to get together and form someone to act as their agent --

MR. LaPLANTE: Energy New England may in fact be such an entity, where a number of the utilities in

Massachusetts that didn't want to work with NMWAC got together and are working with either consultants or with Energy New England to do that. So there really aren't any barriers. Any utility that's a member of NEPOOL can appoint an agent to act on their behalf in dealing in the wholesale market, so they could appoint a consultant or a joint action agency or whatever as their entity.

(Slide.)

I'd like to look ahead a little bit. After the mediation ended this summer, New York and New England did quite a bit of work trying to come to agreement on best practices based on the best practice list of issues and concerns that came out of the mediation. There were three areas I'd like to highlight that New York and New England agreed are best practices and should be included as future enhancements to standard market design.

(Slide.)

The first is hourly bidding. The reason for hourly bidding is that it improves the ability of generators to schedule limited energy resources, both hydro and interruptible gas. Interruptible gas may be only available for a certain set of hours over the day, and if oil is available in the other hours, it's difficult to do that with just a single set of hourly bids for the day. And hydro units also have a similar problem with accurately reflecting opportunity costs with only one set of hourly bids over the course of a day. Dick asked the question earlier about market power and whether having a number of hourly bids, as opposed to just one set of bids per day increases market power. I think in normal conditions, I don't think it matters. If capacity is tight, it may be easier and less costly to the generator or less risky to exercise market power with a set of hourly bids. They wouldn't risk losing so much output. They could only risk one hour as opposed to the whole day. But even with one set of hourly bids, a generator could still take the last two megawatts and put in a very high price and achieve the same thing as raising bids in any given hour.

There is an operational issue associated with hourly bidding that we've had to deal with in our current markets, I know New York has dealt with, which is the ramping between hours of generators when bids change on an hourly boundary. It makes it harder to keep things balanced between hours so you've got to make the software do a lot more work, so there are tradeoffs there. But I think it does allow generators to more accurately reflect some realities.

Chuck talked quite a bit about the co-optimization of energy and reserves in real time. I don't think I need to go into that in any more detail.

Finally, the third is off-line reserve markets. We think there's a need for off-line reserve markets. However, we've had very bad experiences with our off-line reserve markets over the past several years. However, we're working on a structure or an off-line reserve market that could work. New York is a day ahead with an associated real time market, that's one approach. Another, longer-term market for off-line capacity, more like ICAP, may be more appropriate for something that's essentially doing nothing until you need it. So that's an issue that's still out there.

(Slide.)

Finally, a couple of thoughts on developing a standard market design that I'd like to share. First, the bulk of the standard has to be absolute, otherwise, it isn't a standard, and I don't think we'll have gotten anywhere. On the other hand, something needs to be open to innovation and evolution and this keeps it from dying, but also I think allows vendors to compete and would result in a more robust sort of software situation.

(Slide.)

In terms of what should be standardized by the Commission and what should remain open for innovation, I think most of the issues that we spent the morning and the afternoon talking about, locational pricing, the day ahead market, the real time market, financial transmission rights, and especially external transaction scheduling rules, need to be standardized. I think standardizing on ancillary service markets and ICAP is premature for a couple of reasons. I'm not aware of any ancillary service markets that the people that have implemented them would call best practice. And I think there's still a lot of work and experience that needs to be gained before we can come up with good ancillary service market designs. And I think the same holds true for ICAP. It's not clear that the ICAP designs that we have in the Northeast are the best market designs. This is a difficult problem.

I agree with Andy. In theory, we shouldn't need it. We have it. I think if people want to experiment with it and work with it that's fine, but I think standardizing on it is inappropriate. The physical differences across the country I think lend support to this argument. The issues of a hydro system in both operating reserves and capacity reserves are very different than the thermal systems that we have in the Northeast. Hydro is much more reliable, so the capacity view, the view of capacity and the view of operating reserves is different, and having the same sort of ancillary service and capacity markets for both hydro and thermal systems may not work.

I think the other locational pricing the day ahead market, the real time market, FTRs and external transactions that's something that could be standardized across hydro and thermal systems.

MR. KELLY: In the 888 Tariff, energy imbalance service is an ancillary service. When you're talking about we're not yet ready to standardize ancillary services, which ones do you mean? Energy imbalance, the various reserves, reactive power?

MR. LaPLANTE: The real time market I would view as energy imbalance.

MR. KELLY: That's what I thought but I wanted to make sure.

MR. MEAD: Earlier, when you were responding to another question that Kevin posed, I think I heard you say that it was unfortunate that in going to the standard market design, New England would have to give up, at least temporarily, a market for non-spinning reserves and 30-minute operating reserves. I was wondering if you would embellish on that a little bit. Once you have an energy market that pay start-up and no load costs, are there costs of being on reserve for non-spinning reserves and 30-minute reserves that wouldn't be recovered otherwise? And would you expect, in the absence of having some sort of market for these products, that there would be a shortage of these products?

MR. LaPLANTE: What I was trying to say in my response to Kevin was that it's unfortunate that we have a market and we're not going to have one. I'm not disappointed that we're leaving the current non-spin markets behind. But in answer to your second question, if non-spin units are not dispatched frequently for energy and are unable to make up their capital costs or essentially their capital costs generating energy, then there is definitely a need for some form of non-spin or off-line market to incent those units to stay around. We do need, at least in New England, off-line reserves available within ten minutes and 30 minutes. If the energy market isn't providing the revenues, and we haven't seen that the energy market's been able to provide those revenues, we need some sort of off-line market or compensation to make sure we have it.

MR. MEAD: That suggests that perhaps a long term market, rather than a daily market might be a better way.

MR. LaPLANTE: Yes. We're working on a longer term off-like market strategy that we hope to bring forward some time this year.

MR. KELLY: One other question. In New England, are there any hydro units on one river where the output of one hydro unit depends on the output of the other so that they are not independent entities and if the answer is yes, is that a problem or do you have a solution for that in your standard market design?

MR. LaPLANTE: I think just before we went to market, the owners of the hydro units took over dispatch from what was NEPOOL. The river system on the Connecticut River is still interdependent and it is owned by different entities. However, they have been able to work amongst themselves to manage the river flow.

MR. MEAD: Let me just ask one other question.

You mentioned the issue of marginal losses before. Do you have any sense, quantitatively, how big a distortion is there in terms of price? Because the price in Boston doesn't reflect marginal losses in Maine.

How big are marginal losses?

MR. LA PLANTE: I would say in the 1 to 2 percent range, in general. If you're going over a long range, that can increase.

MS. FERNANDEZ: Any more questions?

(No response.)

MS. FERNANDEZ: Thank you, Mr. La Plante.

Our next speaker is Roberto Paliza from the Midwest ISO.

MR. PALIZA: Thank you. I appreciate the opportunity to come here and present the MISO market design.

The MISO market design is work in progress. We have completed the high-level design so far.

(Slide.)

However, we are still working on the detailed design. And what I'm going to present here is that high-level design, which has been completed, and the direction that we are going.

The topics of my presentation are: the Midwest ISO, its current statistics and operation; the proposed midwest market, which is our ultimate goal; the process that we have used so far in order to develop the market design; the main elements of the MISO design framework; the common design elements of the northeast markets, the MISO, and what is included in the FERC Staff white paper; the unique features of the MISO design; and finally, the implementation challenge in getting the midwest market fully operational.

(Slide.)

As a way of introduction, the statistics of the MISO as currently configured are: 25 transmission-owning members, 35 non-TOs. The MISO service territory as currently configured includes 81,000 megawatts of peak load; 74,000 MISO transmission; more than 8 million customers served; 15 states and one Canadian province; three states with retail access.

Also, we have two independent transmission companies that have filed under Appendix I: Detroit ITC, which has been approved, and TransLink, which is awaiting approval. Next, please.

(Slide.)

The MISO is currently operational. The functions listed under Day 1 are currently being phased in, with most of them in operation by February 1, when the MISO tariff goes into effect. Operation of the midwest markets, as proposed by MISO, begins on Day 2, which is hopefully some time in 2003.

The implementation of these midwest markets will be staged in several phases, and this is the reason why you see our design reference to Day 2, Day 3. The MISO market design includes financial transmission rights; I'm going to talk a little more about the design later.

(Slide.)

The MISO design proposes a single market for the midwest. This single market will include the MISO, SPP, and Alliance companies. This market would also include several transmission companies, such as Detroit ITC, TransLink, and others. We also have transmission companies that have not filed their Appendix I's, such as Wisconsin ATC.

The statistics of the proposed midwest market are: over 200,000 megawatts of generation capacity. It will include 23 states and one Canadian province; six states with retail access; approximately 200,000 miles of transmission serving over 30 million customers. As currently proposed, it would be the largest electricity market in the US which is internally coordinated by an RTO.

(Slide.)

Some of the main operational characteristics of the system in the midwest are: they are electrically intertwined, especially in Illinois, Ohio, Indiana, Michigan, and Kentucky, with heavy interdependencies in some regions; the midwest market will include the regions of MAIN, MAPP, SPP and most of ECAR, and also associated agreements such as sharing agreements.

There are over 40 control areas in the midwest which are responsible for dispatch regulation and other important functions. At present, there are four security coordinators and several tariff administrators. The implementation of a single RTO and a single market in the midwest will significantly improve the operation, and eliminate seams.

(Slide.)

This is a pictorial representation of the proposed midwest market. The dark blue is the Midwest ISO region; clear blue is the TransLink members which are not part of the ISO at this point in time; the dark green, south of the Midwest ISO, is SPP; and on the east, in clear green, the Alliance companies.

As you can see, the midwest market will cover a good part of the eastern interconnection. This picture also shows clearly how meshed MISO, SPP and the Alliance companies are.

(Slide.)

Regarding the market design process that we have followed so far, the goal is to develop a design that meets the midwest stakeholder needs while complying with FERC

Order 2000 and emerging FERC standards for markets. It has been an open process from the very beginning, driven by stakeholders.

A focus group of stakeholders and the MISO staff have intensively worked for the last eight months to put together the basis of the design. The results are that the high-level design has been completed, and currently the congestion management working group is working on the detailed design.

And because of this, the timing of this conference is perfect for us, because we will be able to adjust the design as required. The implementation alternatives are being studied parallel with the design, and a staged approach will be used to achieve the ultimate goal, which is getting the midwest markets fully operational. The staged approach will allow us to manage the risk.

(Slide.)

Regarding the MISO design framework, the main elements of the design are: the use of bid-based security-constrained dispatch and LMP pricing for imbalance and congestion. The design includes financial transmission rights in the form of point-to-point rights, options and obligations. Also it includes a real-time market and a day-ahead market.

The MISO design works within a multi-control-area structure. The energy market will be established first, followed by the reserve markets and the regulation markets. This is after all these markets are fully implemented. This is what we call Day 3 operation.

(Slide.)

The following picture shows the main elements of the MISO design and the relationships. At the heart of the system is a bid-based security-constrained dispatch, which balances the load and generation in real time while respecting the system constraints and minimizing the price of meeting load. The inputs to the system are bids from generators and loads, bilateral schedules and self-schedules. LMPs are calculated from the dispatch and used to price congestion imbalance and to settle the financial transmission rights. These financial transmission rights allow market participants to hedge their congestion costs.

(Slide.)

The next three slides show high-level comparisons of the main design elements in the northeast markets.

MR. KELLY: Mr. Paliza, could you say a few words about how the real-time balancing works in a multi-control-area structure, if you know that level of detail yet?

MR. PALIZA: Yes.

Under Day 2, the MISO will be responsible for dispatching the system every five or six minutes. However, between the dispatching intervals, the control areas will be responsible for the regulation function. So there is a coordination process that we need to develop in order to interface with the control areas.

But the basic idea on Day 2 is that the dispatch function is moved to the RTO while the regulation and resales remain with the control areas. Later, on Day 3, the reserve market is established, and that is simultaneously optimized with the energy market, and then maybe later the regulation market also will be phased in.

So, as I said before, this is a staged approach to the implementation, and this is being done in order to minimize the risk, and taking into account the size of the market that we are proposing.

CHAIRMAN WOOD: Is there any approach toward consolidating -- maybe not down to one, but down to a smaller number -- in the number of control areas, or has that discussion not happened yet?

MR. PALIZA: The discussion is not happening. The design does not require it. However, independent transmission companies are proposing, as part of their formation, to consolidate control area functions. An example of that is TransLink, which I believe is proposing to consolidate all the control areas into a single control area operation.

CHAIRMAN WOOD: The number you gave of 40 is for that combined footprint of the four different groups you were talking about is 40 control areas?

MR. PALIZA: That's correct. I believe it is more than 40, closer to 45 also.

(Slide.)

These next three slides will show a high-level comparison of the main design elements of the northeast markets, MISO, and the FERC Staff white paper. Hopefully my understanding of the northeast markets and interpretation of the FERC Staff white paper is correct.

The first slide is about the real-time markets, and shows that in all of these markets they have included simultaneously a balancing of the system while clearing congestion, the use of LMP pricing. All of them allow self-scheduling and bilateral schedules.

(Slide.)

The second slide is about the day-ahead markets, and shows that in all of these existing and proposed markets, day-ahead schedules are developed using a security-constrained dispatch which is consistent with the real-time market. The day-ahead market is voluntary. It allows self-scheduling. Also the day-ahead market uses LMP pricing, and does not require balanced schedules, and the day-ahead schedules are financially binding in all of these markets.

The availability Andy and Chuck talked about earlier is included in all of them. I did not find it in the white paper.

(Slide.)

The third slide is about the transmission markets, and shows that all of these markets include consistent LMP pricing of transmission usage and energy, combined markets for energy and transmission usage. Transmission rights are financial and are not required to pay transmission service, and use rights will be settled on real-time prices if scheduled a day ahead.

In the next set of slides --

(Slide.)

-- I will be getting into more unique features about the MISO design. Allocation of transmission rights is one of the most important topics for stakeholders in the midwest. The congestion management working group is currently working through the issues associated with this subject, and the initial approach is as follows.

There will be an initial allocation of rights during a transition period, which would be followed by a full auction of rights in accordance with this staged-in type of approach that we're using. During the transition period, grandfathered rights will have the choice to convert or not. All OATT contracts will be converted to point-to-point rights, and the length of this transition period has not been determined yet.

If rights are not simultaneously feasible, we will need to develop a methodology to insure that allocated rights are feasible.

MR. MEAD: Can I ask you a question about that?

With regard to the grandfathered, non-OATT rights, what sort of provisions do the holders of these rights have currently that they wouldn't be able to do if they converted to financial rights?

MR. PALIZA: These grandfathered rights are normally long-term rights. They are pre-OATT rights, and our stakeholders felt that initially, at least during the transition period, they would like to have the choice of not converting those rights and those contracts to point-to-point rights.

I think, keeping in mind that -- you know, this is a new market in the midwest. A lot of the stakeholders are concerned about risk, and the phasing approach, and having a transition period to move into these new markets is something that made them feel comfortable. So regarding grandfathered rights, at least a preliminary direction is to allow them to have that choice. Either they can convert to point-to-point rights or they can keep them as they are.

I believe that they are assessing those two alternatives at this point in time.

MR. KELLY: Can I follow up?

RIghts can refer to the right to move 100 megawatts from point A to point B. Sometimes rights mean I have negotiated a right to change my schedule in superior ways to others, or other such sort of terms and conditions of service.

Is it the proposal to grandfather both sets of rights, or just the first set?

MR. PALIZA: That's a very good question, because each contract is unique, and they all have very specific conditions. They are inclusive contracts that bundle energy with transmission.

Now the idea is to basically keep the right to move power. All other characteristics, I think we need to go on a case-by-case basis. As you correctly said, for instance, scheduling these lines, what happens with losses? That's something that we will have to examine case by case.

But the initial intention is just to keep the right to move power. The rest may have to align with the MISO policies.

(Slide.)

Regarding transmission rights, in the MISO design they are financial. They can be defined as point-to-point rights. They can also be options or obligations.

The flow gate is a transmission element or a set of elements which represent transmission operational constraints, such as thermal voltage or stability limitations. I think the previous speakers have talked quite a bit about that.

Flow gates can be defined as having monitor elements only, monitor elements or contingency elements. Flow gates have been used in MAPP and SPP for many years to compute available transit capability and grant transmission service. Also, they have been used for ATC interregional coordination among MAIN, MAPP and SPP regions. Flow gates are currently used in the eastern interconnection.

I was asked to give a brief example of option versus obligation. As I said before, transmission rights can be options, obligations. Settlement of these financial rights depend on the direction of the congestion.

(Slide.)

In this example, point-to-point rights from A to B. We have the LMPs at A, $20; B, $70. If it is an obligation, then the holder receives $50, which is the difference in LMPs. If it is an option, the holder also receives $50, so it doesn't make any difference.

However, if the congestion reverses and therefore the LMPs change, as shown on the right-hand side, the LMP will pay $70. The LMP at A is $70, and the LMP at B is $20.

Then the holder of this right has to pay the difference, which is $50. If it is an option, the holder doesn't have to pay and doesn't receive anything. In this regard, options are more attractive than obligations, because the holder of the right never has to pay.

(Slide.)

Regarding flow gate right characteristics, flow gate rights as proposed for implementation by MISO have the following characteristics. They can be options or obligations. The flow gate right holder is hedged for congestion only on the specified constraint, and the flow gate right holder decides how many flow gate rights will be necessary to hedge its transactions.

The way that MISO has defined these transmission rights, they are different products, and they will be priced in the auction according to market participant needs. By including point-to-point and flow gate rights as options and obligations, the MISO design provides maximum flexibility to the market, and we believe this will force the liquidity of the transmission rights markets.

(Slide.)

About multi-control-area structure: as stated before, in the midwest there are over 40 control areas where the control area operator performs important functions such as dispatch regulation and providing of ancillary services.

The MISO design does not require consolidation of these control areas. The current direction is to accommodate the control areas in the process of creating the markets in the midwest, and our strategy is to first establish the energy market by centralizing the dispatch; then, reserves and regulation markets will be established. These markets will be optimized simultaneously with the energy market.

This phased-in approach was adopted taking into account the size of the proposed market and the need to minimize implementation risk.

(Slide.)

This map shows existing control areas in the midwest region, and also in the neighboring regions. The point of this slide is that there are many control areas with several interconnections among them. The MISO control areas are in blue as currently configured. The first-tier control areas are supposed to be in yellow -- they're in green there -- and the TransLink control areas are in green.

(Slide.)

The midwest includes four existing reserve-sharing agreements: namely, ECAR, MAIN, MAPP, and SPP, which were established to minimize individual control areas' requirements. These reserve-sharing agreements are similar, but each of them has its own characteristics and implementation. In Day 2, MISO will coordinate the operation of these reserve-sharing agreements during a transition period, after which MISO-wide reserve markets will be established. Due to the MISO's size, these reserves may have to be distributed by zones, so that they can be efficiently deployed where needed, and I think the speaker from the New York ISO has made a very good case as to why they need to be distributed, especially in such a large region as the midwest.

(Slide.)

Regarding the long-term resource adequacy, MISO and the stakeholders have discussed the following mechanisms to insure that there will be enough generation to permit loading in the long run. We have discussed ICAP markets, the pricing mechanism, and as the last resource allocation of load-sharing responsibility.

After several days of debate, and taking into account that there are currently no price caps in the midwest, the preliminary conclusion is that the pricing mechanism supported by load-sharing rules may be appropriate for the midwest. However, these require more investigation to make sure that it will work.

The pricing mechanism relies on the assumption that prices can rise, and the generation meets load, and that demand is price-sensitive, so it can respond to the price signals. This is an area where clearly MISO will actively seek inputs from regulators.

MS. FERNANDEZ: Let me ask you a question on load-shedding. Is that going to be price-driven?

MR. PALIZA: Somewhat, yes.

MS. FERNANDEZ: If it is inadequate, you're going to say who gets?

MR. PALIZA: The idea of load-sharing is to allocate the responsibility to the parties who are short, if that is the reason why we get into load-sharing. Sometimes load-sharing happens because of other reasons. You can have a forced outage, you know, and everyone had enough resources. However, you know, all of a sudden, something happened, and we lose several generators or several transmission lines. And in that case, you know, the method calls for a pro rata type of curtailment.

However, if a party is short, and didn't bring enough resources to the table, then we will try to assign load-sharing responsibility to that party if we get into that situation.

(Slide.)

Regarding short-term resource adequacy, all generation will be visible to the MISO. This means that the MISO needs to know what generation is available for redispatch, and the bids for this purpose -- as stated before, the pricing mechanism will be complemented with load-sharing rules to discourage free-riding.

MISO will try to identify, to the extent possible, parties that are short, and accordingly assign load-sharing responsibility, if necessary. By using this approach, MISO will send a clear signal to parties that bring enough resources to the table to meet their obligations that are necessary to avoid curtailments.

(Slide.)

Market power mitigation is an important subject in the design of the midwest markets. During our design process, several market power concerns have been raised, especially related to load pockets in certain subregions of the MISO. This market power constraint will be addressed as part of the market design by working with independent market monitors and stakeholders in developing mitigation schemes for these regions. If approved, they will be incorporated into the implementation of the congestion management system.

The independent market monitor is of course responsible for monitoring and identifying market power in the midwest on an ongoing basis.

(Slide.)

As stated before, MISO will have several transmission companies with whom MISO needs to coordinate differing aspects of our operation. These coordination processes are still under development. However, we know that the creation of internal seams needs to be avoided.

MISO's proposal addresses this particular aspect via the creation of a single market, and establishment of a single market coordinator.

Providing the appropriate incentive for transmission expansion is a hot topic with some of our transcos. This is an area that needs a lot more discussion by MISO stakeholders and regulators. The role of the RTO on this particular subject needs to be clearly defined.

Some of the transco functions may include design, transmission ownership and maintenance, physical operation of the transmission system, work with the MISO on transmission planning, transmission expansion, collect payment for transmission service provided under the MISO tariff.

(Slide.)

Inter-RTO coordination is a subject that MISO is very interested in working with neighboring RTOs. The establishment of large RTOs in the eastern interconnection with capabilities to redispatch their system in real time will require revision and modification of existing coordination mechanisms.

For example, FERC's standard market design will go a long way toward reducing seams. However, either as part of the standard market design or the next step, the individual RTO market designs would need to be coordinated to address issues such as the impact of loop flows on compensation, the impact of real-time redispatch on constraints, transmission rights across RTO boundaries.

The MISO-PJM letter of intent is our first attempt to address coordination issues with the northeast.

(Slide.)

This will be my last slide: implementation challenges. The scale of the MISO operations requires a careful evaluation of implementation alternatives in combination with SPP and Alliance. It will help greatly in resolving seams issues in the midwest.

The key challenge for the Midwest ISO is to successfully implement the single market that has been proposed, which entails the establishment of real-time and day-ahead markets, allocation of financial transmission rights across the entire region, and the coordination of these markets by a single market coordinator -- which, in our proposal, is the MISO. Implementation risks and costs will be managed by staging the implementation and establishing cooperative agreements with other RTOs.

Thank you.

MR. KELLY: Question. Has it been established yet if the MISO will itself establish and run the markets, as opposed to -- during RTO Week, we heard I think Steve

Naumann propose that an ISO or an RTO could set out specifications for a market, put it out for bid and have an independent entity come in and run the market according to specs.

Is that an idea that's still on the table or not?

MR. PALIZA: For the real-time market, I believe that most of our stakeholders', and also the MISO's, position is that the RTO needs to run that market, because of availability concerns. So we need to make sure that that is run by the RTO to insure that availability is taken care of.

Regarding the day-ahead market, I believe that some stakeholders think that could be run by a differing entity, an independent market operator. However, the day-ahead market bundles energy and transmission. That is where transmission is allocated for the next day. As has been said in previous presentations and also in my presentation, the day-ahead market needs to be clear in a consistent way with the real-time market.

At this point in time, our proposal calls for the Midwest ISO to run those two markets, the day-ahead market and the real-time market.

MR. KELLY: Thank you.

MS. FERNANDEZ: Does anyone have any other questions?

CHAIRMAN WOOD: How involved are the stakeholders from SPP and Alliance areas in the development you've got going on?

MR. PALIZA: Because our process has been open from the beginning, they have attended our meetings. They have participated with comments and with their own ideas. So at the day-to-day level, I would say they have been involved.

I'm not sure that they have full participation in the process. But they have kept up with what is going on.

CHAIRMAN WOOD: Explain to me where the MAPP group fits in with the MISO initiative.

MR. PALIZA: MAPP?

CHAIRMAN WOOD: Right. Is the security coordination being transferred over to MISO for the entire MAPP, or exactly what is the nature of that?

MR. PALIZA: Most of the MAPP region is part of the Midwest ISO now, and the Midwest ISO acquired the MAPP control center out in St. Paul. Right now that control center, which is part of the Midwest ISO, performs security coordination for the MAPP region at the direction of the Midwest ISO.

In other words, we have fully integrated that MAPP center into our operation, and security coordination is being performed by the MISO for all the MISO members.

CHAIRMAN WOOD: The planning function for the overall MISO -- where is that?

MR. PALIZA: The planning function is also another function of the MISO which is being done in a collaborative way. In other words, each region performs or develops its own plan. Then the MISO works with all these regions in merging those plans into one that is consistent and makes sense, and assesses -- basically performs an assessment of a full, combined plan for the entire ISO.

In essence, it's a collaborative type of approach with individual regions.

CHAIRMAN WOOD: With regard to the Canadians, you mentioned a seam with PJM being discussed in this agreement that came out last week. You've got a northern seam, I guess, with the IMO, and I don't know where -- I guess Manitoba would be. Which one is not in?

MR. PALIZA: Manitoba Hydro is part of the ISO. Saskatchewan is not.

CHAIRMAN WOOD: What about the seams with regard to the northern border of MISO? Are those people participating in the stakeholder process?

MR. PALIZA: Not yet. I believe that we need to start an inter-RTO type of coordination process with other RTOs in the northeast and north of us.

CHAIRMAN WOOD: I would agree.

And as to the SPP issue, is that filed here? We heard about it several months ago. I just wonder, when is that going to be up and done?

MR. PALIZA: The current goal is to have it completed by the first quarter of this year. I think we're still moving toward that goal. By the end of this quarter the merger hopefully would be completed.

CHAIRMAN WOOD: Okay.

MR. KELLY: I have a question for Mr. La Plante.

On your third slide -- which you don't have to look up -- you said that there were changes from the PJM design due to the physical differences between New England and PJM and policy differences. I thought you said you were going to come back and explain those. I didn't catch the physical differences if you did go back to that.

MR. LA PLANTE: The physical difference is, I consider with the hydro there's a physical difference. The need for electronic dispatch is a physical difference. I think spinning reserve is a physical difference.

I think the key policy sort of difference is the monitoring and mitigation. PJM has taken a different approach to monitoring and mitigation than we've taken historically in New England. So that I think is the major policy difference.

MR. KELLY: Thank you.

CHAIRMAN WOOD: David, you might have mentioned this while I was out. But what percentage of the generation would be divested in New England?

MR. LA PLANTE: Over 75 percent.

MS. FERNANDEZ: Do we have any other last questions?

(No response.)

MS. FERNANDEZ: If not, we're actually going to get out of here before 5:00 o'clock, which seems like a noble goal.

Thank you very much for your presentation. You've been very informative. We'll start up again tomorrow at 9:30.

(Whereupon, at 4:50 p.m., the meeting was recessed, to reconvene at 9:30 a.m., Wednesday, January 23, 2002.)